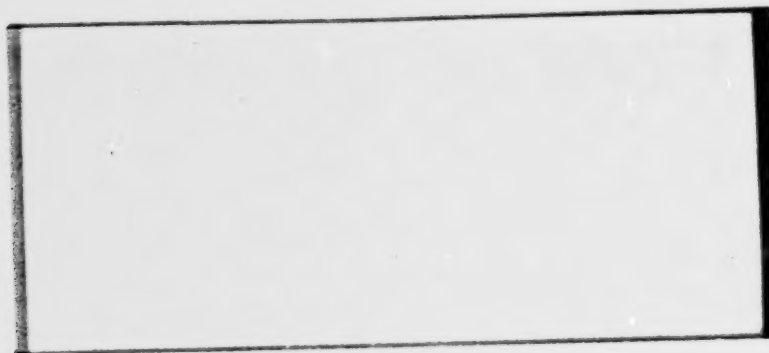
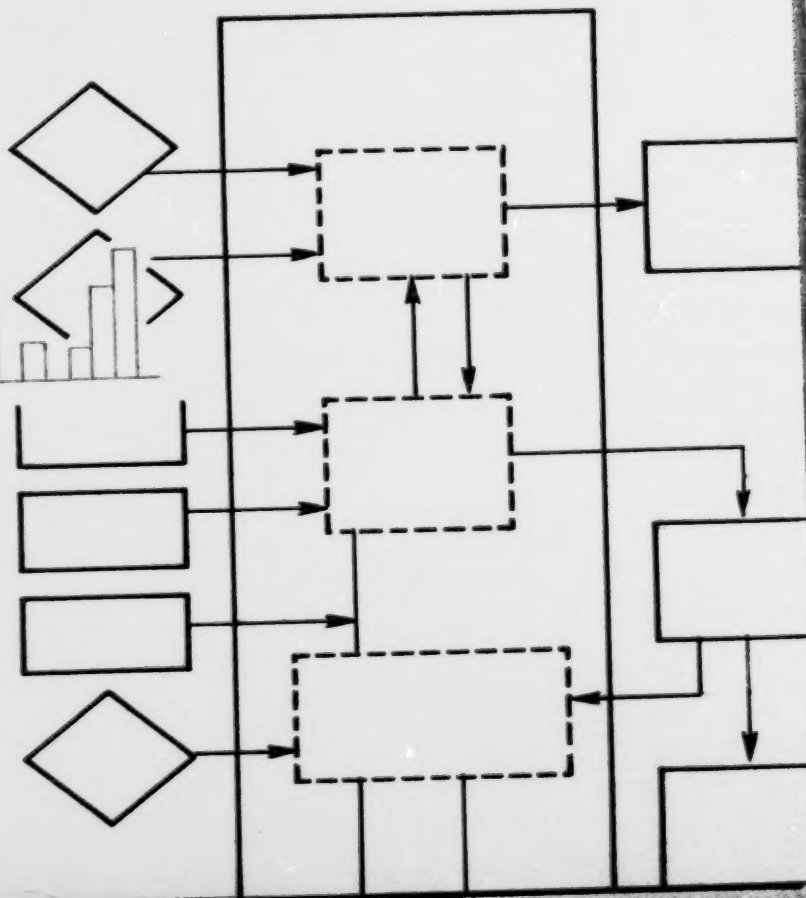
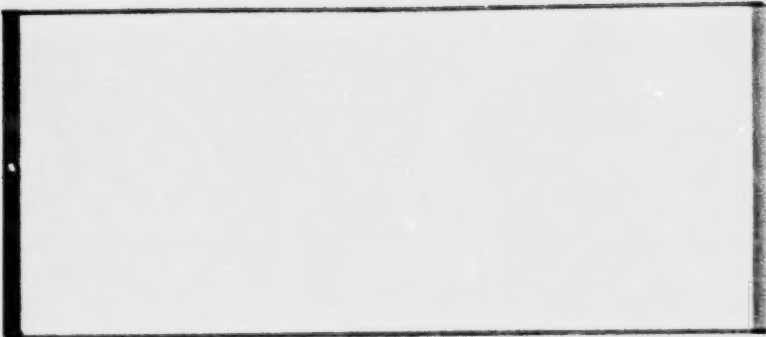


A paper prepared for the
Economic Council of Canada



Un document préparé pour le
Conseil économique du Canada





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DISCUSSION PAPER NO. 243

The Energy Assumptions
Background Paper to the
Twentieth Annual Review

by Bobbi Cain

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All shortcomings of this paper remain the responsibility of the author.

RÉSUMÉ

Les hypothèses relatives à l'énergie que renferment le scénario de référence et les autres simulations présentées dans le Vingtième Exposé annuel se fondent sur les projections à long terme les plus récentes de l'offre et de la demande d'énergie, publiées par des organismes tels que l'Office national de l'énergie et le ministère de l'Énergie, des mines et des ressources. Ces hypothèses reflètent la structure de la politique énergétique canadienne et son évolution au cours des dernières années, particulièrement en ce qui concerne le pétrole brut et le gaz naturel. Comme le secteur de l'énergie n'est pas entièrement développé dans le modèle CANDIDE 2.0, lequel sert à produire les diverses simulations, les contributions du secteur énergétique sont d'abord calculées au moyen d'un système distinct, puis modifiées pour les adapter à la structure du modèle.

Le présent document expose les hypothèses sur lesquelles se fondent les données énergétiques et décrit aussi comment elles sont intégrées au modèle CANDIDE. Après avoir présenté les hypothèses relatives aux projections de l'offre et de la demande de pétrole et de gaz, l'auteur procède à l'analyse de diverses questions portant sur les prix de l'énergie pour ces deux sources de combustible. Il décrit ensuite les politiques en matière de prix, notamment celles

qui sont présentées dans le Programme énergétique national et ses mises à jour, puis il les quantifie d'après nos hypothèses relatives à plusieurs variables de prix principales, comme les cours mondiaux du pétrole brut. L'auteur passe en revue les conséquences des hypothèses en matière de prix et de volume, sous l'angle de leur application aux diverses mesures fiscales et programmes de subventions énumérés dans les politiques pertinentes, de même que les effets des dépenses d'aide fédérale et provinciale au chapitre des immobilisations. Il présente ensuite une description de plusieurs intrants représentant les redevances produites par les nombreuses catégories provinciales de pétrole et de gaz, fortement dépendantes des hypothèses relatives aux prix et aux volumes. Vient ensuite, en conclusion, une analyse des investissements énergétiques nécessaires pour appuyer les hypothèses relatives à la production déjà examinées dans le document.

Ces nombreuses hypothèses en matière énergétique, étroitement liées à la structure des politiques pertinentes, constituent un important apport à toutes les prévisions relatives à l'économie canadienne. Le présent document décrit en détail l'apport de ces hypothèses aux perspectives actuelles quant aux prix, à la production ainsi qu'à la demande intérieure et extérieure de pétrole et de gaz.

Abstract

The energy assumptions included in the 20th Annual Review base case and alternative simulations are based upon the most recent longer-term projections of energy supply and demand released by agencies such as the National Energy Board and the Department of Energy, Mines and Resources. The assumptions reflect the structure of Canadian energy policy as it has evolved over the past several years, with particular reference to crude petroleum and natural gas. Since CANDIDE Model 2.0, which is used to generate the various simulations, does not have a fully-articulated energy sector, the energy inputs are first calculated in a separate energy accounting system and then are aligned to accommodate the structure of the model.

This paper both establishes the assumptions upon which these energy inputs are based and also describes the processes by which these inputs enter the CANDIDE Model. A presentation of projections of oil and gas supply and demand assumptions is followed by a discussion of various energy pricing issues as they relate to the two fuel sources. Pricing policies such as those included in the National Energy Program and its subsequent updates are described and quantified based upon our assumptions for several key pricing variables such as the international crude petroleum price. The implications of these assumptions for prices and volumes as they apply to the various taxation and subsidy measures iterated in the policy provisions are reviewed, as are

federal and provincial capital assistance expenditures. The several royalty revenue inputs relating to the many provincial categories of oil and gas are then described, dependent to a considerable extent upon price and volume assumptions. We conclude the paper with a discussion of energy investment inputs necessary to support our production assumptions reviewed earlier in the paper.

The many energy assumptions, interwoven with the collage of relevant policy measures, are a major input into any forecast of the Canadian economy. This document presents a detailed description of those assumptions as they relate to the present outlook for oil and gas pricing, production, and domestic and foreign demand.

Preface

In this discussion of the energy assumptions incorporated into the base case of the 20th Annual Review, the inputs that are explicitly utilized in CANDIDE Model 2.0 have been presented in two formats. The first of these perhaps requires a further explanation.

In the text the particular input has been described verbally and has then been presented in the more technical format that is used in association with CANDIDE Model 2.0 and is indicated by four asterisks (****). If the variable that is under consideration is an exogenous variable (or has been exogenized), the basic path of that variable throughout the projection period is described using an ASSUME command. For example:

```
**** ASSUME TEFUPTW 239.146 3.0 /GROW 1982 1992
```

means that the exogenous variable for fuel product exports, TEFUPTW, has a base value of 239.146 (million 1971 dollars) in 1982. It is assumed that this variable will increase at a rate of 3.0 per cent per year over the period 1983 to 1992 starting from the base value of 239.146 in 1982. If the particular variable was assumed to increase at other than a constant rate of growth over the period, these would be a string of ten values presenting rates of growth for the years in question. If, in addition to this assumed rate of increment, we wanted to add a further, separate assumption to the same variable, the following command will be seen:

**** INCREASE TEFUPTW 10.0 10.0 10.0 1983 1985

This indicates that, in addition, 10.0 million (\$1971) will be added to that variable during the years 1983 to 1985. If we had wished to subtract a similar value from the variable during the period, a DECREASE command would have been used.

If the variable in question is an endogenous variable any adjustment to it is made through what is termed an additive adjustment. This is basically a projection of the difference in the last period for which actual data is available for the variable between the actual data and the forecasted output of the particular behavioural equation. In this case an ADJUST command is used. For example:

**** ADJUST GRF.YI.REM\$ 782.811 1982 1992

means that the basic adjustment referred to above for the variable GRF.YI.REM\$ (federal income remittances in millions of dollars) is 782.811 in 1982, the latest year where actual data is available, and that it remains at that value throughout the projection period. If further adjustments to the variable are needed they can then be added or subtracted through the INCREASE and DECREASE commands, described earlier in the preface.

In addition to this method of presentation throughout the text, the same information is also gathered in tables related to the discussion in each sector of the paper. These tables are at the end of the text.

THE ENERGY ASSUMPTIONS
BACKGROUND PAPER TO THE 20th ANNUAL REVIEW

INTRODUCTION

Of great importance to any forecast of the Canadian economy are the assumptions made relating to energy. The supply, demand and pricing of commodities such as crude petroleum and natural gas are crucial issues affecting many areas of economic activity. The level of inflation in the economy, the path of the current account of the balance of payments, government revenues and expenditures and the resulting balance -- these are just some of the indicators of economic health that are impacted by the energy assumptions.

Since the CANDIDE Model 2.0 does not have a fully-articulated energy sector, the energy inputs to the CANDIDE Model are first calculated in a separate energy accounting system and are then aligned to accommodate the structure of the Model. In this paper we both establish the assumptions upon which the inputs are based and describe the processes by which these inputs enter the CANDIDE Model. Assumptions are based on information received as of July 12, 1983.

In our documentation these latter entries have been prefaced by four asterisks (****) so that it is clear that they are the direct inputs into the model. We first address the supply and demand of crude petroleum and natural gas. We then turn to a discussion of the various energy pricing issues, and follow that by reviewing

taxation, subsidy and capital assistance measures. The various royalty inputs are next reviewed, and the paper closes with a discussion of energy investment inputs.

ENERGY SUPPLY AND DEMAND

In the first section we review the outlook for both crude petroleum and natural gas supply and demand. The two fuel sources are addressed in turn in order that the reader may have a complete overview of not only the country's domestic capability to supply the fuels, but also the imported requirements necessary in order to balance the various demands originating from domestic and foreign sources.

The Outlook for Crude Petroleum

Crude Petroleum Supply

- Domestic Supply

Estimates of crude petroleum supply are housed in the National Energy Board's most recent statement on Canadian energy released in early September 1981.¹ The hearings and research relevant to this NEB report were completed several months before the Ottawa-Alberta Energy Agreement.² However, the National Energy Board, mindful of the policy environment present at the time of the

hearings (subsequent to the introduction of the National Energy Program), made, in addition to low, high and base case supply estimates, a modified base case estimate. This modified base case was intended to show the effect on oil supply of higher producer netbacks and was predicated on the assumption of an energy agreement. It was this modified base case that we chose for the 18th Annual Review base case. In view of the recent EMR Update³ we have remained with this case for conventional reserves, and have used the high case projection for reserve additions for the 19th Annual Review, as was used in the Update. In lieu of more recent estimates of petroleum supply, we remain with these estimates for the 20th Annual Review.

In Table 1 we illustrate the various components of oil productive capacity that go into the supply estimates in the two cases utilized. We will comment on each category in turn.

Established Reserves: are defined by the NEB as being reserves recoverable under current technology and existing and anticipated economic conditions. These reserves have been specifically proven by drilling, testing or production, and also include a portion of contiguous recoverable reserves that have been judged to exist with reasonable certainty, based on geological, geophysical or similar information. These reserves are estimated to steadily decline.

Reserves Additions: are defined as incremental changes to established reserves due to both appreciation of present reserves and discovery of new pools of crude petroleum. A growing portion of reserves additions is made up of heavy crude oil as opposed to light crude, and a gradual increase in production is expected to arise from enhanced recovery techniques.

Pentanes Plus: are a volatile hydrocarbon liquid, and are generally a by-product obtained from the production and processing of natural gas. The NEB estimates of this crude oil equivalent are anticipated to decline, with increasing volumes required for inputs as miscible fluid requirements into enhanced recovery production techniques.

Oil Sands: are defined as deposits of sand and other rock aggregates which contain hydrocarbons heavier than pentanes which are not recoverable through a well in their natural state. In the base case we include the following oil sands assumptions listed by project.

- **Suncor:** This first commercially-producing oil sands project is anticipated to overcome production delays, and to attain full expansion capacity by 1985 and to maintain such throughout the remainder of the period.

- **Syncrude:** The Syncrude plant, which has been plagued by production delays, is anticipated to reach full capacity by 1984

and to maintain such throughout the remainder of the period. The proposed Syncrude expansion which would have added a third production train (70,000 barrels a day) had been cancelled by the Syncrude-member companies, but has been now re-scheduled on a more limited basis -- the addition of an eventual 20,000 barrels a day capacity -- and as such is included in our assumptions.

- Alsands: With the recent withdrawal of five of the eight members of the Alsands consortium and the collapse of further negotiations, the project's cancellation was announced in 1982. Thus, it is omitted from our scenario.

- Cold Lake: The cancellation of this project was also announced by Esso Resources, and it is assumed that no further activity in the project beyond a minimal pilot plant level takes place until the beginning of the 1990s. Thus, any production would not come on stream until much later in the 1990s, beyond our projection period.

- Canstar: This project is assumed to come on stream in a limited way by 1991. The participation of Petro-Canada, along with Nova, in the project is assumed to ensure its continuation despite recent cutbacks in personnel. It is considered that the last minute scrutiny of the Alsands negotiations will be beneficial to government-industry discussions regarding this project.

- Frontier Oil: Frontier areas are those Canadian areas which have a potential for, but no history of, production. Encouraged by the geological potential of the Hibernia area and optimistic of significant reserves appreciation, the NEB has assumed minimal on-stream production from the Hibernia field in 1986, rising to the 12,000 cubic metres (75,000 barrels) a day level by 1989.

In the 1981 Ottawa-Alberta Energy Agreement certain categories of oil were designated as "new oil" and were accorded a significantly different pricing structure from the remaining oil production. This category was further extended in the Memorandum of Agreement signed in late June 1983.⁴ "New oil" was defined in the 1981 Agreement as consisting of oil from three sources:

a) conventional new oil in Alberta consisting of oil from pools discovered after the end of 1980; "incremental oil" recovered from pools subject to enhanced recovery schemes commencing operation after December 31, 1980; and crude bitumen obtained from experimental and non-integrated oil sands projects commencing operation after December 31, 1980.

b) synthetic oil including existing Suncor and Syncrude production, and

c) oil from Canada Lands defined as areas of Canada such as the Beaufort Sea and Grand Banks Regions that come within federal jurisdiction.⁵

In Table 1 new oil productive capacity includes all reserves additions plus oil sands production and frontier oil and is separately delineated.

For purposes of domestic pricing a further category of new "old" oil was designated in the 1982 Update. Oil discovered in the period after 1973 and qualifying for provincial royalties at "new oil" rates, but not in receipt of the New Oil Reference Price, is now eligible for special pricing concessions called the Special Old Oil Price (SOOP) described at a later date. In addition certain categories of tertiary recovery and experimental projects now qualify for special prices.

In the June 1983 Memorandum of Agreement this category of new "old" oil announced in the May 1982 Update has been revised to receive the New Oil Reference Price as of July 1, 1983. Further discussion of this pricing area will be included when we review our pricing assumptions later in the paper.

Given our assumptions concerning the present reality of the production situation with regards to the Syncrude, Alsands and Cold Lake projects, we see some diminution of present crude petroleum productive capacity with very little improvement until the late 1980s.

- Imported Supply

Using our projections of crude petroleum supply and demand, discussed later, we obtain estimates of supply forthcoming from imported sources. The total crude petroleum productive capacity has in the past been tempered by both demand considerations and by NEB policies. Hence, there have occasionally been, in the past, adjustments made to actual production levels. In 1981 we had the special circumstances of the Alberta cutbacks in response to the National Energy Program. In the past year we have seen further indications of shut-in oil due to imbalances in the supply system and falling levels of demand.

Given our estimates of crude petroleum domestic supply and demand as identified in Table 1, the emerging pattern for imports of crude petroleum suggests a steady decline in the volume of imported oil throughout the remainder of the decade. By 1990, imported volumes will consist only of swap volumes of crude petroleum coming into Canada under the "swap" arrangements with the United States.

The various export and import assumptions in the base case will be further highlighted in a later section of the paper.

Crude Petroleum Demand

In our estimates of the total domestic requirements for crude petroleum, we have used the rate of increase of demand for this

fuel close to that articulated in the assumptions used in the EMR Update.⁶ That is to say, the total demand for crude petroleum decreases by just under 1.0 per cent per year over the projection period and includes the considerable reduction in demand in the 1981-83 period. This demand forecast (Table 1) largely reflects a revised forecast of Canada's energy demands made with EMR's Interfuel Substitution and Demand Model.

This forecast for crude petroleum demand is quite a bit more optimistic than that used in the 18th Annual Review with regards to the effect of the conservation and off-oil measures implemented in the National Energy Program.⁷ It assumes that the impact of these measures will lessen towards the end of the decade. However, we still do not resort to the degree of reduction in overall crude petroleum demand targetted in the National Energy Program.

Table 1 also included estimates, based on NEB policies, of crude petroleum exports. Canadian policies since the mid-70s have been directed towards a severe reduction in exports of crude petroleum. In early 1983 additional volumes of petroleum were authorized for export on very short-term licences and have been in high demand. The relatively small volumes still exported in the majority of the projection period are largely made up of heavy oil, in most cases from Saskatchewan sources.

The Outlook for Natural Gas

Natural Gas Supply

Within its report detailing its decisions arising from the Gas Export Omnibus Hearing in 1982, the National Energy Board included estimates of supply and demand for natural gas.⁸ Table 2 presents the NEB estimates of natural gas supply capability. All of the supply included in this table is forecast to be deliverable from what is termed conventional areas, that is, non-frontier areas.

As in the case of crude petroleum, established reserves are defined by the NEB as those reserves recoverable under current technology and under present and anticipated economic conditions. This estimate includes the supply of reserves, labelled controlled reserves under the control of major gas purchasers, i.e., gas transmission systems. As well, it includes those reserves which are either uncommitted, presently deferred, or beyond economic reach. The 1983 NEB forecast of deliverability from established reserves suggests a profile of declining supply capability from this conventional source towards the end of the 1980s.

Reserves additions again share the same definition as in the case of crude petroleum except that additionally these estimates are influenced by subjective judgments dependent on factors such as market opportunities, drilling activity, economic conditions and potential supply. In the earlier 1981 report, the NEB made

three estimates of reserves additions - a base case and a low and high estimate. In the recent Omnibus Report, one supply scenario is included, and it lies between the earlier base case and high estimate. The reserves additions forecast included in Table 2 is the new NEB forecast, which is based on the assumption that drilling activity will return to the 1981 level by 1985 and will then remain constant to the end of our forecast period.

In our base case, and in the NEB report, the assumption has been made that no frontier natural gas supply is included. This is due to the uncertainties involved in the determination of natural gas supply capability from frontier areas.

Natural Gas Demand

- Domestic Demand

Total domestic natural gas demand increases at an average annual rate of 3.2 per cent over the 1983-1992 period. This includes increases of faster-than-average growth of demand during the recovery period in the first half of the 1980s when the off-oil facets of the NEP provisions are of greatest significance. In the NEB Base Case demand forecast, the share of natural gas in primary energy demand, that is, demand including energy inputs into the generation of other energy forms, will increase over the period, particularly in the industrial and residential sectors. The share

of crude oil within primary energy demand will decline considerably over the same period.

- Export Demand

Table 2 also presents assumptions for total natural gas export requirements. Due to slack U.S. demand for natural gas in 1981 and 1982 actual natural gas exports fell far short of the licensed quantities permissible for export. With the recent announcement of export pricing concessions,⁹ this weakened market is anticipated to gradually recover through 1987 as export pricing problems are resolved and economic activity recovers. We have assumed a different pattern for natural gas export licences than that presented in the NEB report on the basis that the already licensed export volumes presently under-utilized will be utilized at a later date subject to the qualification of sufficient natural gas surplus remaining available according to NEB deliverability tests. The effect of altering this export pattern is to soften the decline in licensed volumes in the latter half of the decade. One important feature of the NEB Omnibus Report was the export licenses granted included provision for LNG exports to Japan starting in 1986. These volumes amounting to 156 BCF per year by 1992 are included in the export estimates in Table 2. Since NEB policy has been clearly stated as to sufficiently provide for Canadian requirements before declaring surplus gas, any additional volumes considered are subject to the constraint of existing supply capabilities (see Table 2).

Supply and Demand Inputs in the Base Case

From the preceding discussion of the supply and demand for natural gas and crude petroleum, we now draw together the assumptions emanating from these scenarios for exports and imports of crude petroleum, natural gas and their products and for domestic consumer demand for these products. As is the case for the remainder of the paper, these assumptions are first presented (as described in the preface) as they appear in CANDIDE inputs. They are later drawn together in an explanatory table at the end of the section.

Import Assumptions

- Crude Petroleum Imports (millions of \$1971)

**** ASSUME TMPETOW

270.372	257.9	199.8	187.8	147.2	100.8	1982	1987
74.3	58.5	54.8	54.8	54.8		1988	1992

In Table 1 we presented the crude petroleum import requirements over the projection period in millions of barrels per year. To these requirements we add "swap" flows of oil averaging 25 million barrels per year. These are flows of crude petroleum which have been exported to the United States in western Canada. Similar volumes are subsequently imported in the eastern part of the country, thus minimizing transportation costs. The movements in the path of these total import volumes are applied to the \$1971

value in 1982 for crude petroleum imports (TMPETOW) to produce the above assumption for this variable. The pattern indicates some considerable diminution in import demand towards the latter part of the decade, but it is strongly influenced by our assumptions concerning supply prospects for various projects and for new oil coming on stream (discussed earlier).

- Imports of Fuel Products (millions of \$1971)

**** ASSUME¹⁰ TMFUPTW 100.147 2.5 /GROW 1982 1992

Imports of fuel products include imports of aviation and marine fuels, the latter mainly being heavy fuel oil, various lubricants and other hydrocarbon based products, and liquified petroleum gaseous products. Heavy fuel oil forms the largest proportion of the category. Our assumption of 2.5 per cent annual average growth in this category reflects the steady moderate growth in these imports. This view of demand growth is supported by the NEB's forecast of average growth of 3.5 per cent over the coming two decades in demand for petro-chemical feedstocks, asphalt, lubricants and greases, and miscellaneous petroleum products.¹¹

Export Assumptions

- Crude Petroleum Exports (millions of \$1971)

**** ASSUME TEPETOW

222.63	264.8	172.9	143.5	119.3		1982	1986
101.9	101.9	101.9	101.9	101.9	101.9	1987	1992

Canadian policy towards exports of crude petroleum became highly restrictive in the mid-1970s. Our present projection of crude petroleum exports is made up of two components. Actual exports are made up of mostly heavy oil and are licensed to decline rapidly to rather minimal quantities by 1985 after some considerable increase in the 1983-84 period (Table 1). The greater part of exports of oil is that composed of "swaps" --crude petroleum exported to the United States from western Canada for subsequent import of similar volumes in eastern Canada. These "swaps" are recorded in the trade statistics, and thus have to be accounted for in our projection. The same assumption of 25 million barrels per year regarding "swaps" for the 1983-1992 period is made for exports as for imports, discussed earlier. The movements in the path of the total export volumes are applied to the estimated \$1971 value for 1982 for crude petroleum exports (TEPETOW) and produce the assumption indicated above.

- Exports of Fuel Products (millions of \$1971)

**** ASSUME TEFUPTW 239.146 3.0 /GROW 1982 1992

Fuel oils and gasoline, together with liquified propane and butane gases, make up the majority of Canadian fuel product exports. These exports have been assumed to increase at an annual rate averaging 3.0 per cent over the projection period. This rate of growth is less than half of the average annual increase over the previous decade and is predicated on particular considerations of the market for liquified hydrocarbon gases.

- Exports of Natural Gas (millions of \$1971)

**** ASSUME TENGASW

216.378	295.7	327.1	411.4	457.1	485.7	1982	1987
499.9	506.8	528.6	471.4	414.3		1988	1992

In the previous section describing natural gas supply and demand we fully discussed the volume assumptions made for natural gas exports including those to Japan (Table 2). These assumptions for billions of cubic feet of natural gas exports have been translated into \$1971 terms applying the pattern of the movements in the BCF volumes to the actual \$1971 value for TENGASW for 1982.

Final Demand Energy Volume Assumptions

- Natural Gas Consumption (millions of \$1971)

**** ASSUME CNR50 465.700 4.5 /GROW 1982 1992

Consumer demand for natural gas is a behavioural variable which is exogenized in order to more fully co-ordinate the particular energy scenario. One of the goals of the National Energy Program is to encourage substitution from crude petroleum to natural gas, as well as to other energy sources. We have assumed a rate of growth of 4.5 per cent reflecting this increased substitution.

- Fuel Oil Products Consumption (millions of \$1971)

**** ASSUME CNR60 434.300 -1.3 /GROW 1982 1992

Other fuel product consumer demand, CNR60, is almost completely made up of fuel oil products with a very small proportion of liquified gaseous products such as propane. In line with the NEP policy directed towards off-oil substitution, the rate of growth of this exogenized variable has been constrained to -1.3 per cent per year over the projection period, somewhat less than the dramatic declines seen in the recent rates of growth. This growth rate is also a reflection of our assumed rate of increase of primary crude petroleum domestic demand.

While we have presented these assumptions within the text as they appear as direct inputs into CANDIDE Model 2.0, it is also

useful to regard them in a more conventional manner. Table 3 presents the various domestic and foreign supply and demand inputs included in the 20th Annual Review base case. For the reader's convenience, a cross reference has been supplied to the discussion of the particular assumption in the text.

ENERGY PRICING

Crude Petroleum Pricing

There are several facets of crude petroleum pricing that must be considered in developing an energy scenario. While Canada's domestic pricing policies are described as "made in Canada" prices, the international price of crude petroleum is an important determinant in any pricing scenario. We will describe in detail both our short- and long-run assumptions in projecting this important indicator. The blended domestic price and the wellhead prices for both oil from "old" and "old new" conventional sources and from "new" sources, while determined by domestic policies, are influenced to some considerable degree by international crude petroleum pricing developments. The derivation of all these prices will be addressed in this section.

International Prices

Canada imports a considerable quantity of crude petroleum. In 1982, 123.4 million barrels of oil were imported, valued at \$5.0 billion in nominal terms, and about 25 per cent (on a gross import basis) of estimated total consumption in the country in 1982. This oil is imported at an international price which is a weighted average of the prices of the various quantities coming from both OPEC and non-OPEC sources. Table 4 presents a calculation which illustrates the major exporters of crude petroleum acquired in Canada in 1981 and 1982. The sources vary over time due to both market and non-market factors. As can be seen from Table 4, there was a shift in 1982 towards Mexican and Venezuelan sources from the traditional Persian Gulf suppliers. We have assumed this revised distribution to maintain over the present year.

As a result of the OPEC Accord reached in March 1983 after many intensive sessions, the benchmark price has been revised downwards to \$29.00 (U.S.) per barrel. We have taken this price as the basis for our average FOB international price for the year 1983 tempered by the various edicts announced by the exporting countries. In the longer term we have assumed that after no change in the real price of oil in 1984 and 1985, the OPEC cartel, on average, will return to a rate of annual real price increase of 0.5 per cent. This pricing assumption includes fairly sharp reductions in the real price in 1982 and in 1983. These assumed price movements are then inflated by the projected rate of

increase in the U.S. GNP price deflator in the Wharton June 1983 post-meeting forecast.

This assumption for the international price recognizes the present very soft market conditions, particularly for crude petroleum exported under spot market pricing. A substantial proportion of crude coming into Canada is imported under contract and is thus assumed to have a somewhat more stable price base, more closely aligned to benchmark prices adjusted for quality differentials.

Presently, the longer-term pricing strategy of the OPEC group is still under evaluation. We have assumed that the Saudi Arabian proposal of a unified pricing system accounting for some measure of economic growth adjusted for an accepted measure of inflation will prevail over the longer term. In 1981 over 35 per cent of our oil imports came from Saudi Arabia, and in general, that country has normally represented the largest single supply source although this was not the case in 1982. Longer run pricing patterns, implicit in the composition of the average Canadian import price, will still presumably be dominated by OPEC pricing strategies, and especially the Saudi Arabian pricing provisions.

In Table 5 we present the assumed path for the international price at source, disaggregating its rate of increase into both the real and inflation components. The price at Montreal includes

estimates of transportation costs from the source to the terminal at Portland, Maine and from Portland to Montreal.

International Trade Prices for Crude Petroleum and Natural Gas

The international pricing assumptions directly influence our projections for the five foreign trade prices connected with crude petroleum and natural gas.

- Export Deflator for Crude Petroleum (1971 = 1.000)

**** ASSUME PTE.US.PETOW 9.9310 -11.8 2.3 4.6 5.3 5.7
4.7 4.1 3.6 4.2 4.0 /GROW 1982 1992

The export deflator for crude petroleum is denominated in U.S. dollars and then converted via the endogenous exchange rate in CANDIDE to Canadian dollars. This variable is projected at the same rate of growth as the international price of crude petroleum at the source.

- Export Deflator for Natural Gas (1971 = 1.000)

**** ASSUME PTE.US.NGASW 17.8060 -13.9 -0.1 4.6 5.3 5.7 4.7
4.1 3.6 4.2 4.0 /GROW 1982 1992

The export deflator for natural gas, denominated in U.S. dollars, moved from 82.6 per cent parity with crude petroleum to

an average of 86 per cent in 1982. It is assumed to then gradually drop to an 82 per cent btu equivalency parity for the remainder of the period. This reduced parity level is one indication of the rather soft and highly competitive market conditions for exports of natural gas and reflects the recent pricing adjustments made by the Canadian government in April and July 1983. According to these adjustments, gas export volumes above a certain level will qualify for special incentive pricing lower than the \$4.40 (U.S.) per mcf established in April 1983. This deflator increases at the same rate as the international price of crude petroleum at the source once the parity adjustment is made.

- Export Deflator for Fuel Products (1971 = 1.000)

**** ASSUME PTE.US.FUPTW 8.5260 -2.5 2.5 4.0 4.5 4.0
4.0 4.0 4.0 4.0 4.0 /GROW 1982 1992

The projection for the export deflator of fuel products, denominated in U.S. dollars, is influenced to some extent by the international price of crude petroleum. This is reflected in the declining real price for these products in the early part of the projection period, but other factors in the production process of these fuels, which are subject to differing and sometimes lower rates of price increase, mitigate the incremental pattern over the remainder of the period.

- Import Deflator for Crude Petroleum (1971 = 1.000)

**** ASSUME PTM.US.PETOW 14.90398 -11.6 4.9 5.7 5.7
6.2 5.3 4.7 4.3 4.9 4.8 /GROW 1982 1992

The import deflator for crude petroleum, denominated in U.S. dollars, is directly influenced by the movements in the international price of crude oil at the source.

- Import Deflator for Fuel Products (1971 = 1.000)

**** ASSUME PTM.US.FUPTW 7.03914 -2.5 2.5 4.0 4.5 4.0 4.0 4.0
4.0 4.0 4.0 /GROW 1982 1992

The projection for the import deflator of fuel products, denominated in U.S. dollars, is derived in a similar fashion to that of the fuel products export deflator. While there are strong influences from the international crude petroleum price, these are again mitigated by other cost factors in the production process, resulting in a somewhat lower incremental rate than in the international price.

Wellhead Crude Petroleum Prices

The Ottawa-Alberta Agreement settled on a pricing schedule for the several categories of oil -- "old" conventional and "new"

oil -- that had been introduced in the National Energy Program. The average field price for conventional old oil was to have increased by \$2.25 semi-annually in 1982, and then by \$4.00 every six months over the period of the agreement. This price was subject to the condition that the overall average field price plus transportation costs to Montreal, adjusted for quality, do not exceed 75 per cent of the international price. In the July 1983 Ottawa/Alberta Agreement Amendment, the controversy over a potential rollback in the conventional wellhead price was resolved. The price will remain at the level of the Jan. 1, 1983 increment to \$29.75 until sufficient upward movement in the international price allows this wellhead price to increase and yet still remain constrained by the 75 per cent ceiling. This does not happen until 1985. Thus the conventional wellhead price remains at \$29.75 until that time, given our international pricing assumptions.

As mentioned before, in the recent EMR Update to the National Energy Program, a special wellhead price (the SOOP) was designated for oil discovered after 1973. This oil qualifies for provincial royalties at "new oil" rates (as defined by Alberta), but was not in receipt of the New Oil Reference Price. According to the Update, the wellhead price for this oil would rise to 75 per cent of the current world price as of the time of the Update and remain at that level (subject to the 75 per cent ceiling) until the conventional "pre 1974" oil price reaches that level. In the June 1983 Amendment to the Agreement this category of oil has now been

accorded the New Oil Reference Price (the NORP) as of July 1, 1983. As shown in Table 5, this "new old" oil price now equals the New Oil Reference Price in 1984, given present projections of international prices.

The New Oil Reference Price, which had applied in varying manners to the several categories of new oil reviewed earlier, must not exceed the actual international price of oil. In the 1982 Update, this price was extended to several small categories of oil that had previously been excluded. Special provisions apply in the application of this price to synthetic oil, especially from the presently established plants, but the general proviso is that the NORP will not exceed the international price. As shown in Table 5, the New Oil Reference Price has been assumed to be the international price at Montreal less transportation to the wellhead.

Domestic Oil Prices

The domestic price of crude petroleum, as was introduced in the National Energy Program, is a blended price, that is a price which is a weighted average of the prices of the various types of oil that make up total domestic consumption. In essence, the blended pricing formula is as follows:

$$P_B = ((P_{W_O} * OIL_{O_O}) + (P_{W_N} * OIL_{O_N}) + (P_N * OIL_N) + (P_M * OIL_M)) / (OIL_{O_O} + OIL_{O_N} - OIL_X + OIL_N + OIL_M)$$

where P_B = Blended Price

P_{W_O} = Wellhead Price for Conventional Oil for Pre 1974 Oil

P_{W_N} = Wellhead Price for Conventional Oil for Post 1974 Oil

P_N = Wellhead Price for New Oil

P_M = International Price of Imported Oil

OIL_{O_O} = Conventional "old old" Oil discovered prior to 1974

OIL_{O_N} = Conventional "old new" oil discovered in 1974-1980 period

OIL_N = New Oil

OIL_M = Imported Oil

Oil_X = Exports of Crude Oil

Transportation costs from the wellhead to domestic sources are included. The Canadian Ownership Charge is also included in this price at 77¢ for the year 1981, and then remains at \$1.15 for the rest of the projection period as was deemed in the April 1983 Federal Budget. This resulting price presented in Table 5 enters directly into domestic price formation through the CANDIDE deflators on a 1971 = 1.000 base in the following manner.

- Consumer Deflator for Other Fuels (Mainly Heating Oil)

**** ASSUME PFCNR60 6.29082 5.4 3.5 4.4 6.0 6.6 5.9 5.4

4.9 5.2 5.0 /GROW 1982 1992

The projection for this consumer deflator for other fuels (mainly heating oil) is derived by regression from the blended price, described above, and an accompanying provincial sales tax rate. The latter tax is a minor influence on the fuel price.

- Consumer Deflator for Gasoline, Oil and Grease

**** ASSUME PFCNT30 3.86075 9.6 4.5 3.6 4.6 5.4 5.3 4.9
4.5 4.5 4.5 /GROW 1982 1992

In the case of the consumer deflator for gasoline, oil and grease, the blended price enters the regression equation in a lagged manner and its impact is combined with that of the relevant provincial sales tax rate. This rate is of greater weight in the projection, as the tax is a more predominant portion of the price.

- Value Added Deflator for Crude Petroleum and Natural Gas Mining

**** ASSUME PXMICP64+96.9 9.90771 24.3 11.5 13.5 11.7 2.5
2.8 2.7 2.4 2.3 2.4 /GROW 1982 1992

The value added deflator for crude petroleum and natural gas mining is projected by regression on the wellhead prices of

conventional oil and of natural gas. The crude petroleum price enters in a lagged manner with the greatest weight on the present year, while the natural gas price enters directly.

Wellhead Natural Gas Prices

The Ottawa-Alberta Agreement was further extended in November 1981 to more fully cover certain details of the original agreement. One of the areas detailed was that of natural gas pricing with respect to both the Alberta border price and to the netback system concerning natural gas revenues. The schedule of increments to the actual average wellhead price of natural gas will be somewhat less than the increments, as dictated in the Agreement, to the Alberta border price due to transportation differentials. The recent June 1983 Amendment laid down a complex pattern of pricing increments and price ceilings for natural gas which have been incorporated into our assumptions. The resulting average wellhead price for natural gas, the one that enters into our energy system, is presented in Table 6. It is this price that was referred to in our description of the projection of the value added deflator for crude petroleum and natural gas mining. In order to maintain the .650 btu parity with the domestic oil price in natural gas pricing during the 18 month period of the Agreement Amendment, and to then even approach it later in the period, it has been necessary to assume that the gas wellhead price will remain constant over a considerable portion of the projection period. During the period of the Amendment, it is the eventual elimination

of the Natural Gas and Gas Liquids Tax which facilitates any increment in the wellhead price.

The export price for natural gas is based on a parity ratio with the international price of crude petroleum. This ratio of gas export prices to international oil prices fell in 1981 to 82.6 per cent, an indication of the softness of the gas export market in the United States. The ratio climbed to 86 per cent in 1982 and as mentioned before, because of Canadian pricing concessions, it is assumed to be reduced to .820 and to remain at that level for the rest of the projection period. Given the decline in international prices, this btu equivalency in 1983 readily approximates the renegotiated gas export price. The incentive pricing scheme for gas, recently announced and referred to earlier, means that this parity will fall somewhat, but not to a great extent. Thus, the relationship between the two prices remains considerably below the actual btu equivalency of 100 per cent. The average export field price of natural gas is shown in Table 6. This price directly influences our projection of the natural gas export deflator discussed earlier. The net back to natural gas producers is a weighting of the export and domestic prices by the relevant proportionate quantities distributed to domestic and export markets and falls between the two prices.

Domestic Natural Gas Prices

In the National Energy Program there was a stated intention to gradually reduce the ratio reflecting the relationship between oil and natural gas prices from 85 per cent to 65 per cent in order to encourage substitution from oil to gas. At the same time a natural gas and gas liquids tax, added to the wellhead price and transportation costs, was introduced. It was later clarified in the September 1981 Ottawa-Alberta Agreement that this tax would be calculated so as to maintain the 65 per cent parity relationship inclusive of wellhead and transportation costs. It should be noted here that transportation costs per unit are much higher for natural gas than for crude petroleum, and make up a much greater proportion of the unit price.

Since the reduction in international oil prices and the implied reduction in prices in Canada, the maintenance of the 65 per cent parity relationship in future domestic gas pricing has become a critical issue. As was noted by the Minister of Energy, Mines and Resources in the House of Commons on March 30, 1983,¹² the room for the natural gas and gas liquids tax is quickly being eroded. Once that tax has fallen to zero, in view of the terms of the Ottawa-Alberta Agreement on agreed increments to wellhead prices, the continued increases in the wellhead price would necessitate an eventual violation of the 65 per cent parity. In the June 1983 Amendment, it was stated that this parity would be enforced until

after the end of 1984. At that time the scheduled increments to the producer would again take place until after 1986.

In this base case, we have assumed that the parity is first enforced and then is indeed exceeded, and that the semi-annual increment in the natural gas wellhead price takes place as agreed until the end of 1986. It is then assumed that the wellhead price is frozen at the end-of-1986 level, and as can be seen from Table 6, the btu equivalency is gradually approached.

The Toronto City Gate price for natural gas presented in Table 6 includes both the natural gas and gas liquids tax, the extended Canadian Ownership Charge and transportation costs added to the average price for domestic gas at the wellhead. That price enters into the CANDIDE system in the following manner.

- Consumer Deflator for Natural Gas

```
**** ASSUME PFCNR50  4.43599 11.8 3.5 6.1 10.4 10.0 6.3 4.2
      4.0 4.0 4.2  /GROW 1982 1992
```

The consumer deflator for natural gas is projected by regression, the main determinants of which are current and lagged values of the Toronto City Gate price for natural gas and a relatively minor impact from the associated provincial sales tax.

The various assumptions for foreign and domestic petroleum and natural gas deflators, which have been explicitly described throughout the text, are also presented in a more traditional format in Table 7. The base value level referred to in the table is the level of the particular deflator on a 1971 = 1.000 base in 1982. The relevant growth rates are applied to this base value for the remainder of the period in question.

The Blending Fund

Before we move into a discussion of the various energy taxation and subsidy programs introduced in both the National Energy Program and the later Ottawa-Alberta Agreement, let us briefly turn to a discussion of the components of the blended pricing system.

In this system a set of refinery levies was introduced that balanced the necessary outlays to subsidize both imports of oil and the higher priced categories of new oil. Levied on all oil requirements, the petroleum compensation charge is classified as an indirect tax and will be included in our discussion of the various taxation measures.

Oil importers are subsidized at the refinery the difference between the international price paid for the oil and the wellhead price plus transportation costs. This subsidy program for imported oil was introduced in 1974 and was in theory to be

balanced by tax revenues on crude petroleum exports. However, with the subsequent volatile movements in the crude petroleum international price combined with declining volumes of oil exports, the program began to incur severe deficits in the late 1970's. This was one of the factors in the introduction of the blended pricing system.

The other subsidy programs involve subsidies, in effect, directed to the producers of new, "old new" and synthetic oil amounting to the difference between the new oil price paid to them and the wellhead price plus transportation costs. Both the import subsidy and the new and synthetic oil subsidy will be further described in our discussion of the various subsidy assumptions.

One point concerning the blended pricing system remains to be clarified. In the National Energy Program it was stated that the blended price would not go beyond 85 per cent of either the international price or the U.S. price, whichever was less. However, it has been made clear in the Ottawa-Alberta Agreement that the overriding concern in determining the petroleum compensation charge will be the balancing of the blending fund.¹³ With the recent softness in international markets, it appears that the 85 per cent ceiling may well continue to be surpassed. In this case, the policy of balancing the fund has been clearly followed.

TAXATION MEASURES RELATED TO ENERGY

Indirect Taxes, Gasoline Excise Tax (Millions of dollars)

The original gasoline excise tax was introduced in 1975 at 10¢ per gallon, was later revised to 7¢ per gallon and then to 1.5¢ per litre. It is a unit tax, dependent on the volume of sales rather than on movements in price. Thus, it is projected to increase at the rate close to our assumed value of increase in gasoline consumption, in this case, a decrease of 1.5 per cent per year. Thus, our projection for the revenues of this tax, which are exogenous in the model, is as follows:

**** ASSUME GRF.IT.GAS\$ 408.0 -1.5 /GROW 1982 1992

We had previously included our projection of the Natural Gas and Gas Liquids Tax within the variable described above. The NGGLT is now included in Indirect Taxes, Other, outlined at a later point in the paper.

Indirect Taxes, Oil Export Tax (Millions of dollars)

The oil export tax system has been expanded with the advent of the NEP to include both an additional tax on marine and aviation products and a refund of 50 per cent of the export tax on crude oil to the exporting provinces. The marine and aviation tax was subsequently removed in the April 1983 Budget. In view of the

several parts of this tax we first make an assumption that the basic tax is zero throughout the projection period.

**** ASSUME GRF.IT.OILX\$ 0.0 1982 1992

- Oil Export Tax on Crude Petroleum and Products

**** INCREASE GRF.IT.OILX\$ 1054.5 496.5 352.9 337.3 1982 1985
276.1 227.4 224.1 217.6 210.7 207.3 205.8 1986 1992

The oil export tax on crude petroleum and products was originally introduced in late 1973. This tax is levied on the difference between the international price of crude petroleum and the wellhead price, or the domestic price accruing to the producers or refiners, in the case of products. Thus, the calculation is as follows:

$$TX_{OILX} = ((P_M - P_{WA} - T_{RO}) * OIL_X) + (OIL_{XPR} * (P_M - P_B))$$

where TX_{OILX} = Export tax revenues on crude oil and products

P_M = International price of oil at Montreal

P_{WA} = Average Wellhead price of old and new conventional oil

P_B = Blended oil price

T_{RO} = Oil transportation costs - wellhead to refinery

OIL_X = Exports of crude petroleum

OIL_{XPR} = Exports of crude petroleum products

The resulting estimates from this calculation are entered as an INCREASE to the exogenous variable.

- Marine and Aviation Fuel Tax

**** INCREASE GRF.IT.OILX\$	173.	56.7	0.0	0.0	0.0	1982	1986
	0.0	0.0	0.0	0.0	0.0	0.0	1987 1992

Within the National Energy Program the oil export tax was extended to marine and aviation fuels and labelled the Transportation Fuel Compensation Recovery Charge (TFCRC). Our estimates of these tax revenues were based on figures obtained from several sources and reflected the capture for the federal government of the rent accrued on the international sale of these fuels. In the April 1983 Federal Budget, this tax was rescinded, thus our projection rests at zero for the remainder of the projection period after April 30, 1983.

- Aviation Turbine Fuel Tax

**** DECREASE GRF.IT.OILX\$	55.3	19.0	0.0	0.0	0.0	1982	1986
	0.0	0.0	0.0	0.0	0.0	0.0	1987 1992

It was announced on February 1, 1982 by the Minister of State for Finance that the portion of the Transportation Fuel Compensation Recovery Charge with respect to aviation turbine fuel had been terminated. In its place, an amendment to the Income Tax Act has been introduced such that rents on the sales to purchases at international prices now accrue to the government. In the April 1983 Federal Budget, this tax was also rescinded. For the

period beyond April 30, 1983, adjustment for this tax has changed to zero. This change will also be applied in our calculation of direct tax revenues discussed later.

- Rebate to Provinces of Crude Oil Export Tax

In the National Energy Program the intention was announced to share on a fifty/fifty basis the proceeds of the oil export tax on crude petroleum with the exporting provinces. This rebate is anticipated to be treated by the National Accounts as a transfer from the federal government to the provinces and the oil export tax is recorded net of such transfers. They will be included in a later portion of this document and will consist of an adjustment amounting to 50 per cent of the tax revenues on crude oil exports. No revenues were transferred under this proviso in 1981, however a payment of \$448 million made in April 1982 in respect of accrued liabilities is included in our assumptions.

Since the treatment of this transfer has been changed to a net basis in respect of the Oil Export Tax, an adjustment must be made to the tax revenues as follows:

***	DECREASE	GRF.IT.OILX\$	502.2	198.7	116.9	98.7	1982	1985			
			67.8	44.0	45.2	46.1	46.6	47.3	47.7	1986	1992

Indirect Taxes, Other (Millions of dollars)

The category, indirect taxes, other, which includes all other indirect taxes excluding the manufacturers' sales tax, customs duties and the various excise taxes, has been expanded to include the revenues from the Petroleum Compensation Charge, the Natural Gas and Gas Liquids Tax and the Canadian Ownership Charge.

**** ASSUME GRF.IT.OTH\$ 188.0 6.5 5.5 6.1 6.9 6.4 6.4 6.4
6.4 6.4 6.4 /GROW 1982 1992

The base projection for federal indirect taxes, other, is assumed to increase at a constant rate of real growth, inflated by the estimated rate of change in the GNP deflator.

- Petroleum Compensation Charge

**** INCREASE GRF.IT.OTH\$ 3283.0 1151.3 1297.2 1735.4 1982 1985
1921.6 2119.8 2319.5 2496.2 2634.8 2742.0 2784.8 1986 1992

The rationale behind the Petroleum Compensation Charge was discussed earlier in our survey of the blended pricing procedure. The revenues arising from the imposition of the charge are essentially calculated by the following equation:

$$PCC = (OIL_M * (P_M - T_{RO} - P_{WA})) + (OIL_N * (P_N - T_{RO} - P_{WA})) - GEN_R$$

where PCC = Petroleum Compensation Charge revenue

OIL_M = Imports of crude petroleum

OIL_N = Production of new, "old new" and synthetic oil

P_M = International crude petroleum price at Montreal

P_N = New oil reference price

P_{WA} = Average Wellhead price of old and new conventional oil

T_{RO} = Average transportation charge for oil from wellhead

GEN_R = Contribution for government general revenues (assumed to be phased out fully by the end of 1982)

The actual unit petroleum compensation charge is calculated by dividing the total revenues by the domestic plus export demand for bulk oil product exports. The revenues generated by this system are added by an INCREASE command to other indirect tax revenues.

- Canadian Ownership Charge

**** INCREASE GRF.IT.OTH\$	908.0	927.7	939.1	943.6		1982	1985
	948.0	954.8	954.8	956.9	964.8	969.1	978.1
							1986 1992

The intention to levy a Canadian Ownership Charge to partially finance public sector purchases in the energy area was announced in the National Energy Program. Early in 1981 it was announced that with Petro-Canada's purchase of Petrofina, a charge levied over a 25 month period from May 1981 to May 1983 would finance 85 per cent of the purchase price. A second announcement concerned the extension of this charge to finance the public

participation in the DOME financial restructuring package. We have assumed this package will go forward, and have extended the tax to the end of November 1983. Then, in the April 1983 Federal Budget it was announced that this tax would continue to be levied in order to collect revenues to pursue the government's stated energy objectives. This charge, levied on both oil and natural gas purchases, has been referred to earlier in our discussion of crude petroleum pricing.

The revenues of the Canadian Ownership Charge are calculated as follows:

$$COC = (COC_{BL} * CONS_{OIL}) + (COC_{MCF} * CONS_{GAS} * .90)$$

where COC = Canadian Ownership Charge Revenues

COC_{BL} = Canadian Ownership Charge per barrel of oil

COC_{MCF} = Canadian Ownership Charge per MCF of gas

$CONS_{OIL}$ = Domestic Consumption of crude petroleum

$CONS_{GAS}$ = Domestic Consumption of natural gas.

Estimates of the revenues from this charge have been included as an increment to other indirect tax revenues.

- Natural Gas and Gas Liquids Tax

The natural gas and gas liquids tax on all sales of natural gas was introduced in the National Energy Program. This tax was

reduced to a zero rate as of October 1, 1981 for exports of natural gas in the Ottawa-Alberta Agreement and that principle was confirmed in the subsequent Ottawa-British Columbia accord. Thus, the tax is only levied on domestic sales of natural gas and on the majority of natural gas liquids sales. Within the National Accounts system this tax has been allocated to indirect taxes, other.

**** INCREASE GRF.IT.OTH\$ 1238.0 1169.3 0.0 1982 1984
0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 1985 1992

The factors entering the calculation of the natural gas liquids tax include gas transportation costs, the Canadian Ownership Charge and the desire to maintain the parity relationship between the natural gas price at Toronto City Gate and the blended price at Toronto Refinery Gate at 65 per cent. In order to maintain this relationship, the lower energy prices dictate rapidly diminishing room between the prices for this tax. By 1983, revenues are shrinking as room rapidly decreases to zero. It should be noted that these tax revenues thus are very dependent upon movements in the world price as reflected in the blended price. The tax's calculation is based on the following formula, and is then multiplied by the level of domestic consumption:

$$NGGLT = ((P_B / 5.8 * PARITY) - P_{GW} - T_{RG}) - COC_{MCF}$$

where NGGLT = Natural gas and gas liquids tax

P_B = Blended price of oil

PARITY = Assumed parity between oil and gas
P_{GW} = Wellhead price of natural gas
T_{RG} = Average transportation cost of natural gas
COC_{MCF} = Canadian Ownership Charge per MCF

Direct Taxes, Corporations (Millions of dollars)

Several additive adjustments are made to the output of the equation for direct tax revenues from corporations.

**** ADJUST GRF.DT.CCRP\$ -2091.748 1982 1992

The above basic additive adjustment is that arising from our analysis of the single equation error of the particular system.

- Petroleum and Gas Revenue Tax

**** INCREASE GRF.DT.CCRP\$ 1613. 2792. 2984. 3309. 3668. 1982 1986
3875. 4005. 4084. 4139. 4047. 3952. 1987 1992

The petroleum and gas revenue tax was first introduced in the National Energy Program and was subsequently modified in the later Ottawa-Alberta Agreement and in other clarifications released by Energy, Mines and Resources.

This tax is set at a rate of 16 per cent as of January 1, 1982 on non-synthetic oils with a 25 per cent resource allowance on revenues. The tax on some categories of synthetic oils will be

reduced to 10.7 per cent until the project achieves payout. Given the resource allowance and other detailed exemptions, an effective rate of 12 per cent is deemed to be a reasonable assumption.

The calculation of the tax revenues involves the estimation of operating costs for the various categories of oil and gas involved. A sample calculation, in this case for conventional old (pre 1974) oil, can be derived as follows:

$$\text{REV.PGRT}_{\text{O}_\text{O}} = [\text{OIL}_{\text{O}_\text{O}} * (\text{P}_{\text{W}_\text{O}} - \text{OC}_\text{C})] * \text{TXRT}_{\text{PGRT}}$$

where $\text{REV.PGRT}_{\text{O}_\text{O}}$ = PGRT revenues re old oil production

$\text{OIL}_{\text{O}_\text{O}}$ = Old (pre-1974) conventional oil production

$\text{P}_{\text{W}_\text{O}}$ = Wellhead Price for Old Oil

OC_C = Estimate of operating costs for conventional oil

$\text{TXRT}_{\text{PGRT}}$ = Effective PGRT tax rate.

These revenues arising from the five relevant categories of oil and three categories of gas sales are then summed to give the total tax revenues included in the adjustment made to direct tax revenues, federal.

The 1982 value is obtained from the National Accounts. The revenues are added as an incremental adjustment to the additive

adjustment of the equation for direct tax revenues from corporations.

**** DECREASE GRF.DT.CCRP\$ 231.2 342.3 259.0 196.5 1982 1985
196.5 196.5 196.5 196.5 196.5 196.5 196.5 1986 1992

In the 1982 EMR Update to the National Energy Program, the Small Producers PGRT Exemption was introduced. This annual credit of up to \$250,000 against the PGRT liability of certain groups of associated companies is available to offset taxes on revenue earned after May 31, 1982. Our estimates of this exemption are based on data released at the time of the Update's release. It has been assumed that this exemption will remain in place after the expiry of the Ottawa-Alberta Agreement.

**** DECREASE GRF.DT.CCRP\$ 20. 25. 25. 25. 25. 1983 1987
25. 25. 25. 25. 25. 1988 1992

In the recent April 1983 Federal Budget, it was announced that modifications were proposed to the Petroleum and Gas Revenue Tax for enhanced oil recovery projects. Liabilities under the tax would be eliminated until such time as the projects in question pay back their capital costs. Estimates of the revenue loss arising from this modification are applied as a DECREASE command to direct tax revenues, and are based on estimates produced in the associated budget papers.

- Incremental Oil Revenue Tax

**** INCREASE GRF.DT.CCRP\$ 205. 565. 682. 353. 125. 1982 1986
22. 0.0 0.0 0.0 0.0 0.0 1987 1992

The incremental oil revenue tax (IORT) was announced in the Ottawa-Alberta accord on September 1, 1981. This tax, which was introduced January 1, 1982, is set to recover for the federal government 50 per cent of the incremental old oil revenues¹⁴, after the deduction of royalties. Incremental old oil revenues are defined as those between the actual production revenues received on old oil and those which would have been received under the NEP wellhead price schedule. A portion of Suncor production, the pre-expansion volumes, is also included in this definition. In the April 1983 Federal Budget, the suspension of this tax from conventional oil from June 1, 1982 to May 31, 1983 announced in the Energy Update has been extended to May 31, 1984. These revenues are very elastic with respect to movements in the international price, and are dependent to a great extent on the life of the particular production source. In this scenario they fall to zero in 1988 as the price differentials are reduced, due to the lower international prices. Since these incremental revenues are deductible from income for corporate taxation purposes, an adjustment will be described later in the paper to account for this fact.

The equation for the calculation of the IORT is as follows:

$$\begin{aligned} \text{IORT} = & .5 * ((P_{WA} - P_{NEP} - (\text{ROY}_O * (P_{WA} - P_{NEP})) * \text{OIL}_O) \\ & + (P_N - P_{NEP} - (\text{ROY}_{OS} * (P_N - P_{NEP})) * (.75 * \text{OIL}_{OS1}))) \end{aligned}$$

where IORT = Incremental oil revenue tax

P_{WA} = Wellhead price of crude petroleum

P_N = Wellhead price of new oil

P_{NEP} = Wellhead oil price under NEP schedule

ROY_O = Effective royalty rate on old oil

OIL_O = Old oil production

ROY_{OS} = Effective rate of oil sands petroleum production

OIL_{OS1} = Production for Suncor oil sands plant

Since the Suncor pre-expansion production is at maximum and old oil production is steadily projected to decrease, these revenues will steadily decline over the latter half of the projection period, depending on wellhead price movements, and as we see, in this case, will fall to zero. The reduction of the IORT granted from June 1, 1982 to May 31, 1984 in the Update and the April 1983 Budget was effected by adjusting the base price, P_{NEP} , to equal the wellhead price for the period in question. Thus, reduced revenues accrue to the federal government during the 1982-1984 period.

- Aviation Turbine Fuel Tax

**** INCREASE GRF.DT.CCRP\$	55.3	19.0	0.0	0.0	0.0		1982	1986
	0.0	0.0	0.0	0.0	0.0	0.0	1987	1992

As mentioned in our previous discussion of the oil export tax, certain elements of the TFCRC have been redirected to a direct tax measure. This recovery of the rents connected with the international sale of aviation turbine fuels is now incrementally added to the additive adjustment for direct taxes, corporations. As mentioned before, this tax has been eliminated as of April 30, 1983 in the April 1983 Federal Budget.

Net Corporate Taxable Income (Millions of dollars)

**** ADJUST GTF.V.PCT	2071.04		1982	1992
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The path for the basic additive adjustment to the equation for the net corporate taxable income is predicated on movements in the single equation error for the latter part of the sample period.

**** INCREASE GTF.V.PCT	3280.	3305.	2045.	1722.	1961.		1982	1986
	2239.	2530.	2859.	3231.	3651.	3600.		1987 1992

An increment to this adjustment is made to account for several factors involved in the integration of the November 1981 Budget into CANDIDE Model 2.0.15

- Gross Incremental Revenue Deduction

**** DECREASE GTF.V.PCT	1828.2	1694.7	2017.0	958.7	1982	1985
	305.9	53.1	0.0	0.0	0.0	0.0
					1986	1992

In connection with the imposition of the Incremental Oil Revenue Tax (IORT), it was announced that in the Ottawa-Alberta Agreement the incremental income is deductible for taxation purposes. Thus net corporate taxable income is reduced by the incremental revenue through a DECREASE command. This reduction in taxable corporate income will impact corporate tax revenues according to the appropriate tax rate.

The incremental revenue is calculated according to the following formula:

$$IR = ((P_{WA} - P_{NEP}) * OIL_O) + ((P_N - P_{NEP}) * OIL_{OS1} * .75)$$

where IR = Incremental revenue

P_{WA} = Average Wellhead price of old and new conventional oil

P_N = New Oil Reference Price

P_{NEP} = Wellhead price in National Energy Program

OIL_O = Conventional old oil

OIL_{OS1} = Suncor production

As in the case of the calculation of the taxation revenues, the

base price, P_{NEP} , has been adjusted to take account of the remission over the June 1982 to May 1984 period.

Federal Transfers to Provinces, Other (Millions of dollars)

**** ASSUME GEF.TPR.OTHR\$ 1498.8 1982 1982

**** ASSUME GEF.TPR.OTHR\$ 1500.0 1983 1992

Federal transfers to provinces, other, are miscellaneous transfers of various sorts including transfers to agencies such as the former DRIE. This category is exogenously projected at a constant nominal value throughout the projection period.

- Transfer of Crude Oil Export Tax

**** INCREASE GEF.TPR.OTHR\$ 502.2 198.9 116.9 98.7 1982 1986
67.8 44.0 45.2 46.1 46.6 47.3 47.7 1987 1992

In our discussion of the oil export tax, it was stated that 50 per cent of the proceeds of the tax on crude petroleum exports was announced in the NEP to be directed to the exporting provinces. In the case of the composition of our present oil exports, these transfers would largely go to the province of Saskatchewan with a small portion flowing to other exporters. The estimates of the transferred tax portion are an incremental addition to the exogenous projections of federal transfers to

provinces, other, and include a payment in 1982 reflecting accumulated credits from November 1980 to December 1981.

Provincial Tax Rate on Diesel Fuel and Gasoline (\$ per Gallon)

**** ASSUME GTP.R.D+GAS .35207 7.6 2.5 1.6 2.6 3.4 3.3
2.9 2.5 2.5 2.5 /GROW 1982 1992

The average of the dollar per gallon provincial tax rates on diesel fuel and gasoline is now an ad valorem tax in the majority of provinces. Thus, increments in the price of gasoline affect movements in this tax rate. We have projected this variable at the rate of increase in the consumer deflator for gasoline less two percentage points. This adjustment compensates for the portion of the tax not under an ad valorem regime.

All of the adjustments to CANDIDE relating to the various taxation and transfer measures described in the past section are also presented in tabular form in Table 8. In the case of several of these variables, we have effected the necessary input to the model by a further adjustment to the additive adjustment to the endogenous variable determined in the routine updating sequence of the model. This is unlike the method used in the case of an exogenous variable where we have explicitly adjusted the basic assumption for the particular variable.

SUBSIDIES AND CAPITAL ASSISTANCE MEASURES

Subsidies

Oil Import Subsidy (Millions of dollars)

**** ASSUME GEF.SUB.OILIM\$	1744.	552.8	449.0	493.7	1982	1985
	357.5	185.1	80.3	16.1	0.0	0.0
					1986	1992

In our discussion of the blended pricing system, we referred to the oil import subsidy program, a program that has been in effect since 1974. The payments associated with this program are dependent on two major factors -- the level of imports of crude petroleum and the level of the international price relative to the Canadian price paid to the producers. The equation which calculates the import subsidy payments is relatively straightforward:

$$SUB_M = OIL_M * (P_M - T_{RO} - P_{WA})$$

where SUB_M = Oil import subsidy payments

OIL_M = Imports of crude petroleum

P_M = International oil price at Montreal/brl.

T_{RO} = Transportation costs from wellhead to refiner/brl.

P_{WA} = Average Wellhead price of conventional new and old oil/brl.

Non-agricultural, Non-oil Federal Subsidies (Millions of dollars)

The CANDIDE title of this category is somewhat of a misnomer, since with the introduction of the Syncrude levy program the classification has included, in addition to non-agricultural subsidies, the subsidies associated with synthetic oil.

**** ASSUME GEF.SUB.NA-OIL\$ 1537.0 7.0 /GROW 1982 1992

The basic projection for this exogenous variable takes into account assumptions concerning the growth of a variety of subsidy programs such as freight rate and other railway subsidies, support of the CBC and employment training programs and other miscellaneous subsidy programs. We have assumed that this category will increase at an annual rate of growth of 7 per cent, a rate which reflects little real growth over the period.

- Subsidies on New and Synthetic Oil

**** INCREASE GEF.SUB.NA-OIL\$ 1298. 598.5 848.2 1241.7 1982 1985
1564.1 1934.8 2239.2 2480.2 2688.0 2802.5 2983.8 1986 1992

The subsidy program on new and synthetic crude petroleum was originally addressed in our discussion of the blending fund. The payments in this program are dependent on several factors -- the international price of oil, the level of production of new oil as well as the quantities classified as new oil, and the level of production of synthetic oil. If more oil is coming on stream from

synthetic or frontier sources, the new oil subsidy payments will be higher.

The calculation of these subsidies in our system involves the following type of specification:

$$SUB_N = OIL_N * (P_N - T_{RO} - P_{WA})$$

where SUB_N = Subsidies on new, "old new" and synthetic oil

OIL_N = New oil (both new, "old new" and synthetic)

P_N = New oil reference price/brl.

T_{RO} = Transportation costs for oil/brl.

P_{WA} = Average Wellhead price of conventional new and old oil/br.

The resulting estimates of subsidy payments are added by INCREASE command to the exogenous variable.

- Western Development Fund Subsidy

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**** INCREASE GEF.SUB.NA-OIL$ 650.0 779.0 900.0 900.0 1983 1986
      900. 900. 900. 900. 900. 900.                      1987 1992
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Originally introduced in the October 1980 Budget with the National Energy Program, the monies allocated to the Western Development Fund were re-allocated in the 1981 Budget and some of the expenditures were delayed. In consideration of the nature of the proposed private sector allocation of these expenditures, it

was decided that the Western Development Fund monies would be designated as subsidies.

- Subsidies Associated with Unidentified Programs

**** INCREASE GEF.SUB.NA-OIL\$	704.	785.	1519.	2411.	1982	1985		
	3255.	3817.	3817.	3817.	3817.	3817	1986	1992

In the federal expenditure programs associated with the November 1981 budget, certain allocations have been made to subsidies which are directed towards, as yet, unidentified programs. A portion of these subsidy expenditures have now been identified in the April 1983 Federal Budget as being allocated towards the development and financing of export markets and to stimulate housing construction in selective areas. Thus, this increment includes certain expenditures related to these measures.

- Laterals Fund Subsidies

**** INCREASE GEF.SUB.NA-OIL\$	30.	60.	60.	1983	1985
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In the EMR Update, it was announced that the federal government would establish a "laterals fund" of \$500 million to pay for construction of laterals in the Province of Quebec. As yet, little information is available on either the timing or disposition of these funds. It has been assumed that the funds will be dispensed in line with the construction of the TQM

pipeline in the Province of Quebec. We have further assumed that the expenditure will be allocated 30 per cent to subsidies and 70 per cent to capital assistance. Thus, we made an increment to non-agricultural subsidies to account for the subsidy portion of the expenditure.

- Additional Special Recovery Program Subsidies

**** INCREASE GEF.SUB.NA-OIL\$	53.15	36.34	24.99	1983	1985
	16.36	3.18		1986	1987

In the April 1983 Federal Budget it was stated that, of the monies allocated for the Special Recovery Program, some \$700 million had been previously planned for projects which were not being accelerated. As such, we have included a portion of these funds in subsidies (as previously mentioned) and we now make an additional increment to account for our estimate of the new subsidy funds committed to the Program.

A category of expenditures which had been included in subsidies is the federal portion of the petroleum incentives program (PIP) payments. It has been decided that due to the nature of these incentive payments they are more fittingly associated with federal capital assistance programs where they now have been allocated. A certain portion of these PIP payments is now shared by the Alberta government as indicated in the Ottawa-Alberta Agreement and these have been transferred to the provincial sector.

Provincial Subsidies (Millions of dollars)

**** ADJUST GEP.SUB\$ 289.765 1982 1992

The equation for provincial subsidies, many of which are directed towards housing, has the above additive adjustment arising from the single equation error.

The portion of petroleum incentive payments shared by the Alberta government and previously allocated to provincial subsidies has now also been transferred to provincial capital assistance payments and will be discussed later.

- Alberta Service Grant

**** INCREASE GEP.SUB\$	250.0	0.0	0.0	0.0	0.0	0.0	1982	1986
	0.0	0.0	0.0	0.0	0.0	0.0	1987	1992

In its April 1982 announcement of the Alberta Oil and Gas Activity Program, the Alberta government included the establishment of a \$250 million grant program for certain service and maintenance work done by the industry between April 15, 1982 and October 31, 1982. This grant was included as an adjustment to provincial subsidy payments in the year 1982.

Capital Assistance

Federal Capital Assistance (Millions of dollars)

**** ASSUME GEF.CAS\$ 864.0 6.5 5.5 6.1 6.9 6.4 6.4
6.4 6.4 6.4 6.4 /GROW 1982 1992

The base projection of federal capital assistance expenditures is assumed to increase at the rate of growth of the GNE deflator, in other terms, a constant rate of real growth. This is a rate similar to the long-term growth rate of this category of expenditures.

As was mentioned in our discussion of subsidies, the monies allocated for Western Development Fund expenditures have been re-allocated to subsidies. The initial estimates of these expenditures published at the time of the release of the National Energy Program have been subject to revision and deferment in later figures published with the November 1981 budget. Further revisions were announced in the June 1982 Budget.

- Petroleum Incentive Programs

**** INCREASE GEF.CAS\$ 935.2 1056.5 1369.2 1780.0 1982 1985
1722.8 1661.7 1595.4 1523.9 1446.5 1361.4 1310. 1986 1992

The expenditures connected with the petroleum incentives programs first announced in the National Energy Program are

allocated for a wide range of incentives to the crude petroleum and natural gas mining industry.¹⁶ The National Accounts allocation of these expenditures was for a time in question. It is now certain that the appropriate allocation would be to capital assistance, and this decision has been implemented.¹⁷

The federal portion of the petroleum incentives program expenditures has been estimated to amount to 65 per cent of the total funds. This estimate has been added by INCREASE command to the basic projection. It is assumed to increase till mid-decade (based on official estimates published in budget papers) and then is assumed to decline in both nominal and real terms to the end of the projection period, as the programs are implemented and come to fruition.

- Laterals Fund

**** INCREASE GEF.CASS 70. 140. 140. 1983 1985

As was earlier discussed during our survey of federal subsidy expenditures, 70 per cent of the monies earmarked for the Laterals Fund has been allocated to capital assistance over the 1983-85 period. Thus we have made an increment to federal capital assistance payments to take account of our assumptions concerning the expenditures allocated for the Laterals Fund.

- Capital Assistance Expenditures on Unidentified Programs

**** INCREASE GEF.CAS\$ 491.8 1540.9 1913.5 2191.6 1982 1985
2295.2 2405.7 2405.7 2405.7 2405.7 2405.7 2405.7 1986 1992

As was discussed in the case of subsidy payments, certain federal expenditures, presently unidentified as to specific programs, were included in the November 1981 Budget estimates. A portion of these funds was allocated to federal capital assistance and has been included by INCREASE command in our estimate of capital assistance. The expenditures are assumed to remain constant in nominal terms over the 1986-92 period.

As in the case of subsidies, a portion of the expenditures planned for the Special Recovery Program have already been allocated in earlier budgets. Thus, monies under the Program directed toward research and development expenditures, home renovations, and many of the proposed capital projects falling under the federal umbrella are partly included in the "unidentified programs" and have been accelerated or augmented.

- Additional Special Recovery Program Expenditures

**** INCREASE GEF.CASS	122.97	181.34	112.69	1983	1985
22.0				1986	1986

As mentioned above only part of the monies allocated through capital assistance towards the Special Recovery Program enunciated in the April 1983 Federal Budget have been previously included. In this increment we add the remainder of the expenditures to account for our estimate of the funds arising out of capital assistance expenditures.

Capital Assistance to Persons

A portion of capital assistance expenditures are directed to what is classified as persons, i.e., non corporate bodies. Much of these expenditures is related to energy, in particular the off-oil substitution and insulation programs. This variable has been exogenised in the CANDIDE Model in order to take account more fully of these energy-related expenditures.

**** ASSU GE.CAS.PES	435.800	7.0	/GROW	1982	1992
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The basic component of capital assistance to persons which includes programs such as expenditures concerning CMHC assistance is projected to increase at 7.0 per cent per annum over the

forecast period, suggesting close to a constant rate of real growth.

- Canada Oil Substitution Program

****INCREASE GE.CAS.PE\$	203.2	263.0	287.0	312.0	1982	1985
	312.0	312.0	312.0	312.0	312.0	312.0
					1986	1992

The Canada Oil Substitution Program (COSP) is designed to assist the conversion of oil-based heating systems to alternative fuel forms. Expenditures on this program, added by increase command to capital assistance expenditures to persons, are estimated to increase fairly rapidly until 1985 and to then be maintained at that 1985 level for the remainder of the projection period. This implies a declining level of expenditure in real terms over the 1985-92 period as the program's impact stabilises.

- Canadian Home Insulation Program

**** INCREASE GE.CAS.PE\$	225.0	247.5	272.3	299.5	1982	1985
	329.4	360.0	360.0	360.0	360.0	360.0
					1986	1992

The Canadian Home Insulation Program (CHIP) was expanded at the time of the National Energy Program in order to more fully assist homeowners to upgrade the insulation present in their residences. Expenditures arising from this program are included in capital assistance to persons and are added by the increase command to the

exogenised base value. Estimates of expenditures, which include assistance regarding urea formaldehyde foam insulation (UFFI) installations, are forecast to increase until 1987, after which time they will stabilise in nominal terms, implying a real reduction.

- Additional Canada Home Renovation Plan Expenditures

**** INCREASE GE.CAS.PE\$ 90. 30. 1983 1984

As mentioned in our discussion of capital assistance expenditures by the federal government, a portion are directed towards augmenting the Canada Home Renovation Plan. These monies are by their nature designated as capital assistance to persons, and as such, are added by increase command to this CANDIDE category.

Provincial Capital Assistance (Millions of dollars)

**** ASSUME GEP.CAS\$ 220.7 6.5 5.5 6.1 6.9 6.4 6.4 6.4
6.4 6.4 6.4 /GROW 1982 1992

As in the case of the base projection of federal capital assistance expenditures, the provincial component has also been assumed to increase at a constant rate of real growth, inflated by the GNE deflator.

- Alberta Canadianization Grants

**** INCREASE GEP.CAS\$ 0.0 180. 300. 450. 550. 500. 1982 1987
500. 500. 500. 500. 500. 1988 1992

In the Ottawa-Alberta accord, the province of Alberta undertook to devote certain monies to what were termed "Canadianization" programs. These were particularly related to the encouragement of off-oil substitution in Eastern Canada. Our estimates of the funds allocated to these grant programs are added by INCREASE command to provincial capital assistance expenditures. They are assumed to remain constant in nominal terms beyond the period of the accord.

- Petroleum Incentives Programs

**** INCREASE GEP.CAS\$ 191.3 704. 872. 1093. 1062. 1982 1986
1029. 994. 955. 913. 868. 840. 1987 1992

In our discussion of federal capital assistance, it was stated that the provincial government had agreed in the Ottawa-Alberta agreement to share the petroleum incentive program expenditures. Alberta has undertaken to fund the portion of the expenditures resident in that province.

We have estimated this provincial share of the funds to be 35 per cent of the total estimated expenditures, and as in the federal case, the monies have been allocated to capital assistance. Our estimates are added to this provincial category by INCREASE command, and are assumed to decline in nominal terms beyond the period of the agreement.

As in previous cases, our assumptions relating to both subsidies and capital assistance expenditures are presented in the traditional tabular form in Table 9. The assumptions include both federal and provincial program expenditures.

ROYALTIES

The calculation of the various royalty revenues accruing to both provincial and federal governments is disaggregated into a fair amount of detail in the energy accounting system. We do not model the royalty systems of the various provinces involved in the industry, but instead concentrate on the Alberta and British Columbia systems, making appropriate modifications to certain factors to nullify prospective overprediction. Our projections include the recent changes to the royalty schedule announced by the Alberta government in the Alberta Oil and Gas Activity Program.¹⁸ They do not include the changes to the Saskatchewan system announced in July 1982 which are, as yet, unquantifiable. We first turn to a discussion of federal royalty revenues and then

to the question of provincial resource royalty revenues, close to 90 per cent of which are directly related to the crude petroleum and natural gas industry.

Federal Royalties (millions of dollars)

**** ASSUME GRF.YI.ROY\$	25.0	25.0	25.0	25.0	25.0	25.0	1982	1987
	25.0	25.0	25.0	25.0	25.0		1988	1992

The basic projection for federal royalty revenues is presently maintained at a constant level throughout the projection period. No federal energy royalties are included in the base case as no production is presently forthcoming from the Canada Lands other than Hibernia, in whose case we have assumed that the royalty revenues will accrue to the province.

Provincial Royalties (Millions of dollars)

Before entering into a discussion of provincial crown royalties, it should first be established that a distinction is made by the provinces between new and old oil which is unlike the distinction made in the National Energy Program and referred to earlier in the paper. Old oil and gas are defined in Alberta as production arising from wells in operation prior to January 1, 1974. In the recent Update, this distinction has been used in connection with the special wellhead price for "new" old oil. Thus, in order to properly calculate royalty revenues accruing to the provinces it

is necessary to disaggregate production into these types of categories, allowing for freehold reserves production. This latter category is where mineral rights are privately owned.

**** ASSUME GRP.YI.ROY\$ 0.0 1982 1992

To first establish a base projection which we will later augment by the various royalty revenues, we make a basic assumption of zero for provincial royalties.

- Old Oil Royalties

**** INCREASE GRP.YI.ROY\$ 3886.8 4200. 3578. 3059. 2728. 1982 1986
2426. 2138. 1847. 1566. 1312. 1076. 1987 1992

Old oil royalties are those revenues collected from established reserves in production by the end of 1973. These revenues are calculated as follows:

$$ROY_{OO} = 12 * SA_O + ((\gamma * SA_O * (P_{WA} - P_{SO})) / P_{WA}) * N_{WO} * P_{WA}$$

where ROY_{OO} = Total royalty revenue on old oil

SA_O = Basic old oil royalty established in barrels per month, equivalent to 25 per cent of a well's production of oil greater than 1200 barrels a month, plus an additional 180 barrels

- γ = Royalty factor, estimated in our calculations at 1.550
- P_{WA} = Average wellhead price for old oil
- P_{SO} = Select price, established at 8.10 per barrel
- N_{WO} = Estimate of number of individual old wells

The estimates forthcoming from this calculation suggest declining old oil royalty revenues as old oil production declines. With the recent schedule revisions, the effective royalty rate produced by this calculation lies in the area of 40 per cent gradually falling to less than 30 per cent.

- New Oil Royalties

**** INCREASE GRP.YI.ROY\$ 376. 818. 1041. 1258. 1640. 1982 1986
1983. 2321. 2608. 2863. 3134. 3361. 1987 1991

Royalty revenues on new oil, a category of oil which mainly includes reserves additions (referred to in an earlier section of the paper), are calculated by a similar formula, only with a different parameter set for the royalty factor. Thus:

$$ROY_{NO} = 12 * SA_N + ((\sigma * SA_N (P_{WA} - P_{SN}))/P_{WA}) * N_{WN} * P_{WA}$$

where ROY_{NO} = Total royalty revenue on new oil

SA_N = Basic new oil royalty established in barrels per month, equivalent to 25 per cent of a well's

production of oil greater than 1200 barrels a month, plus an additional 180 barrels.

σ = Royalty factor, estimated in our calculations at .600

P_{WA} = Wellhead price for old oil

P_{SN} = Select price, established at 8.10 per barrel

N_{NW} = Estimate of number of individual new oil wells.

In this calculation the wellhead price of old oil has been used rather than the new oil reference price. This is one factor used in the formula in order both to generalize the formula across provinces, and to take into consideration the recent royalty concessions made for certain types of new oil. The effective royalty rate arising from this calculation falls in the range of 28 to 30 per cent.

- Oil Sands Royalties

***** INCREASE GRP.YI.ROY\$	281.	394.	407.	425.	449.	1982	1986
	477.	502.	525.	547.	592.	716.	1987 1992

The royalty revenue calculation for oil sands production is a more generalized formula and again utilizes the basic wellhead price to account for special concessions. The formula is as follows:

$$ROY_{OS} = .2 * (OIL_{OS} - 10.8) * (P_W - T_{ROS}) + .864 * (P_W - T_{ROS})$$

where ROY_{OS} = Royalty revenue on oil sands production

OIL_{OS} = Oil sands annual production, where the 10.8 stands for the exemption of 900,000 monthly barrels

P_W = Wellhead price on old conventional oil

T_{ROS} = Oil sands transportation allowance

The effective royalty rate generated by this formula falls in the 18 per cent range. The revenues increase with the advent of somewhat greater production towards the end of the period.

- Hibernia Royalties

**** INCREASE GRP.YI.ROY\$	11.1	68.7	103.3	129.7	135.2	1986	1990
	141.7	148.5				1991	1992

With the advent of on-stream oil production from the Hibernia fields, an assumption had to be made with reference to the disposition of royalty revenues. In view of the Ottawa-Nova Scotia accord we have made the assumption that the relatively low volumes of revenues in question will accrue to the provincial governments. The calculation involved in the estimation of these revenues is as follows:

$$ROY_{OFF} = P_{OF} * ROY_{FER} * OIL_H$$

where ROY_{OFF} = Royalty revenue to provincial government from frontier oil

- P_{OF} = New oil reference price less frontier transportation costs
 ROY_{FER} = Effective royalty rate on frontier oil, assumed to be 10 per cent
 OIL_H = Oil production from Hibernia field

This assumption concerning provincial royalties from this project may be regarded as debatable. It quite possibly will be resolved with the advent of a Newfoundland-Ottawa accord, as has been the case in the recent Nova Scotia-Ottawa agreement.

- Gas Export Royalties

**** INCREASE GRP.YI.ROYS 1551. 1600. 1764. 2322. 2729. 1982 1986
3073. 3318. 3554. 3787. 3523. 3223. 1987 1992

Gas export royalties are calculated by a fairly straightforward formula, but the disposition of the revenues is handled in a somewhat different manner. A considerable portion of natural gas exports arise from British Columbia sources, thus the collection of resource rents at time of writing is controlled by the British Columbia Petroleum Corporation. This agency buys the gas at one price and then sells it for export at a higher price, in essence extracting a resource rent. We will later explain an adjustment which is made to royalty revenues to account for the transactions of the BCPC as well as other crown corporations.

Gas export royalties are calculated by the following method:

$$ROY_{GX} = EF_{GX} * .80 * GAS_X * (P_{GX} - P_{SGX})$$

where ROY_{GX} = Natural gas export royalty revenues

EF_{GX} = Effective royalty rate for gas exports (.430 for most of the projection period)

GAS_X = Volume of natural gas exported to U.S.

P_{GX} = Field price for gas exports

P_{SGX} = Select price for gas exports, assumed to be 10¢

The revenues accruing to governments are strongly influenced by our assumptions concerning natural gas exports.

- Old Gas Royalties

**** INCREASE GRP.YI.ROY\$ 826. 1084. 1242. 1502. 1741. 1982 1986
1706. 1615. 1498. 1397. 1319. 1251. 1987 1992

As discussed before, a distinction is also made between old gas (pre-1974) and new gas (post-1973). With the recent Alberta revisions, royalties are estimated to be collected on 70 per cent of domestic natural gas sales and involve an effective rate of around 41 per cent. Old gas royalties are calculated by the following method:

$$ROY_{GO} = EF_{GO} * .70 * G_{DO} * (P_{WG} - P_{SGO})$$

where ROY_{GO} = Royalty revenues on old gas sales

EF_{GO} = Effective royalty rate on old gas

G_{DO} = Domestic old gas sales
 P_{WG} = Wellhead price of natural gas
 P_{SGO} = Select price for old gas, assumed to be 50¢

These revenues expand with increased volume of sales to the domestic market plus with increased price levels.

- New Gas Royalties

**** INCREASE GRP.YI.ROYS 5.4 22.4 57.2 141. 270. 396. 1982 1987
544. 739. 951. 1118. 1299. 1988 1992

Domestic sales of new gas qualify for a much lower effective rate of 31 per cent. The royalty revenues are calculated by the following formula:

$$ROY_{GN} = EF_{GN} * G_{DN} * P_{WG}$$

where ROY_{GN} = Royalty revenues on new gas sales

$$EF_{GN} = \text{Effective royalty rate on new gas}$$

G_{DN} = Domestic new gas sales

$$P_{WG} = \text{Wellhead price of natural gas}$$

It should be noted that the royalties are levied on the full complement of domestic new gas sales as they are available for the market.

- Adjustment re Crown Corporation Profits

**** DECREASE GRP.YI.ROY\$ 735.2 797.2 784.1 883.7 960.5 1982 1986
1023.5 1061.7 1097.4 1133.1 1041.0 941.4 1987 1992

As was mentioned before, an adjustment is made to provincial royalties to account for royalties classified as profits of crown corporations in the National Accounts. These profits include rents accruing to crown corporations such as the British Columbia Petroleum Corporation and SASKOIL. Our estimate of this adjustment is calculated as follows:

$$ROY_{ADJ} = (.262 * ROY_{GX}) + (.09 * ROY_{OO})$$

where ROY_{ADJ} = Total royalty revenues to be adjusted

ROY_{GX} = Gas export royalty revenues

ROY_{OO} = Old oil royalty revenues

Adjustment to Profits of Government Business Enterprises
(Millions of dollars)

**** ADJUST Y.PROFBT.GOVBE\$ -76.358 1982 1992

The above additive adjustment on the behavioural equation for profits of government business enterprises accounts for the single equation error, excluding the error caused by the exclusion of certain crown corporation resource revenues.

- Adjustment re Crown Corporation Profits

**** INCREASE Y.PROF.BT.GOV.BES 735.2 797.2 784.1 883.7 1982 1985
960.5 1023.5 1061.7 1097.4 1133.1 1041.0 941.4 1986 1992

The revenues involved in the adjustment for Crown Corporation Profits more properly belong in the category "profits of government business enterprises". They are added by INCREASE command to the additive adjustment for the equation.

Federal Income Remittances (Millions of dollars)

**** ADJUST GRP.YI.REM\$ 782.811 1982 1992

The above additive adjustment to the behavioural equation for federal income remittances accounts for the single equation error. This equation and its provincial and municipal counterpart use profits of government business enterprises as an independent variable. It is not logical that profits accruing to provincial crown corporations should impact federal or local income remittances. Therefore, we first make an offsetting adjustment to the federal income remittance equation.

**** INCREASE GRP.YI.REM\$ -375.0 -406.6 -399.9 -450.7 1982 1985
-489.9 -522.0 -541.5 -559.7 -577.9 -530.9 -480.1 1986 1992

Using the coefficient (.510) of the relevant independent variable, Y.PROFBT.GOVBE\$, we make a negative adjustment to the additive adjustment to the federal remittances equation.

Municipal Income Remittances (Millions of dollars)

**** ADJUST GRL.YI.REM\$ -40.407 1982 1982

**** ADJUST GRL.YI.REM\$ -11.799 1983 1992

The additive adjustment to the behavioural equation for municipal income remittances has to be altered in the second year to take account of the auto-correlation coefficient on the equation.

**** INCREASE GRL.YI.REM\$	-31.8	-33.4	-39.0	-34.1	1982	1985
	-36.7	-45.1	-46.1	-46.4	-46.5	-47.7 -41.2 1986 1992

The independent variable, Y.PROFBT.GOVBE\$, enters the equation for municipal income remittances with a one and two year lag. Thus, in order to calculate the adjustment to account for the effect of the increment to government profits plus the effect of the auto-correlation coefficient, a rather complex routine must be followed. This calculation results in an offsetting adjustment to the additive adjustment to the equation.

Our royalty assumptions for the various categories of oil and gas are presented in Table 10. These adjustments include the

effect of royalty revenues on profits of crown corporations and their further impact on federal and municipal remittances through the particular equation specification of the model.

ENERGY INVESTMENT

In our discussion of energy supply we referred to the advent of production from various projects, or the availability of such production given physical constraints. In order for production to become available and be transported, certain investment expenditures are assumed to be made. Three categories of energy investment, previously endogenous, are now exogenously determined in the CANDIDE Model; that determination is arrived at with considerable input from the energy accounting system.

The lags involved in the construction of the various mega-projects and the timing of such projects have been shown to be of vital importance to the economy. In this section we will set out the various investment assumptions related to the energy sector. These assumptions are stated in millions of 1971 dollars.

Crude Petroleum and Natural Gas Mining: Construction

**** ASSUME IMIPC64+96.9 1959.40 6.5 6.0 5.5 5.5 5.5 5.5
5.5 5.5 5.5 5.5 /GROW 1982 1992

The basic projection for construction investment in the crude petroleum and natural gas mining industry includes investment in all conventional forms of gas and oil as well as frontier and offshore development. The equation has been exogenized and this basic projection separated from the various categories of oil sands investment.

In this scenario we have assumed some recovery from the present reduction in the rate of growth of oil and gas construction activity in the near-term. This assumption may seem optimistic in terms of the industry's concerns with the present investment and pricing climate. However, this assumed rate of growth is only mediocre in an industry which has achieved rather spectacular levels of activity over the past decade despite other periods of uncertainty. It should also be remembered that this projection includes expenditures on projects such as the heavy oil upgrader in Saskatchewan. We now turn to the various categories of oil sands investment.

- Suncor Oil Sands Project

**** INCREASE IMIPC64+96.9	22.8	22.8	20.2	20.2	20.2	1982	1986
	20.2	20.2	20.2	20.2	20.2	1987	1992

The Suncor project, both in the Athabasca region and in associated pilot projects in the Cold Lake region, is anticipated to engage in a moderate level of both replacement and maintenance

activity over the projection period. This activity is expected to propel the project towards a level of full expansion production by mid decade. The estimates, based on information from EMR, have been translated from 1975 dollars for model purposes.

- Syncrude Oil Sands Project

**** INCREASE IMIPC64+96.9	60.7	25.2	45.2	45.2	50.2	1982	1986
50.2	50.2	50.2	50.2	50.2	50.2	1987	1992

Due to the state of uncertainty regarding the economic climate surrounding oil sands activity, the eight member companies of the Syncrude project initially cancelled the proposed expansion of the mining project. In June, 1983 favourable financial concessions from the Alberta government have elicited a positive decision from the partners to undertake a partial, 20,000 barrel a day expansion. In this base case we have included some further investment activity beyond estimates of that required for replacement and maintenance purposes in order to account for this expansion investment. These estimates, translated from \$1975 for model purposes, are based on present knowledge of the requirements for these purposes.

- Alsands Oil Sands Project

**** INCREASE IMIPC64+96.9	20.2	0.0	0.0	0.0	0.0	0.0	1982	1986
	0.0	0.0	0.0	0.0	0.0	0.0	1987	1992

The Alsands Project was cancelled late in April 1982, and we have assumed that, other than expenditures to wind-down the project, no further investment activity takes place. As was mentioned earlier in our discussion of supply of crude petroleum, this cancellation diminishes the potential supply by the end of the decade by a considerable amount.

- Cold Lake Oil Sands Project

**** INCREASE IMIPC64+96.9	10.1	7.6	7.6	7.6	7.6	7.6	1982	1987
	7.6	7.6	20.2	81.0	146.8		1988	1992

With the announcement by Esso Resources of the cancellation of the Cold Lake in-situ project, an assumption has been made that minimal investment expenditures will continue in support of the present pilot project and research and development. It has been further assumed that there will be a revival of the project at the end of the decade resulting in production coming on stream in the mid-1990s, beyond the projection period. Estimates of the build-up expenditures at the turn of the decade are based on information from project personnel.

- Canstar Oil Sands Project

**** INCREASE IMIPC64+96.9	20.2	20.2	20.2	20.2		1982	1985
60.7	131.6	227.8	341.7	399.9	283.5	212.6	1986 1992

While the Canstar mining project has been assumed to be delayed two years from earlier projections, it is assumed to go forward, with peak investment activity at the end of the decade. The estimates of construction investment flows are based on estimates obtained concerning the Alsands Project, which while locationally different, is a project of a similar nature.

**** INCREASE IMIPC64+96.9	21.0	22.0	23.3	25.0	27.0	1983	1987
----------------------------	------	------	------	------	------	------	------

In the April 1983 Federal Budget, the 7 per cent investment tax credit was extended to heavy construction equipment. Since several categories of energy investment are exogenous in the CANDIDE model, it has been necessary to estimate the impact of this incentive on the various energy investment expenditures in order to properly account for the tax's impact. As such, an increment has been added to crude petroleum and natural gas mining construction investment as indicated above.

Crude Petroleum and Natural Gas Mining: Machinery & Equipment

**** ASSUME IMIPM64+96.9 255.8 6.0 5.5 5.0 5.0 5.0 5.0 5.0
5.0 5.0 5.0 /GROW 1982 1992

The basic projection that replaces the exogenized equation for crude petroleum and natural gas mining investment contains a similar degree of optimism as that associated with construction activity. The level of machinery and equipment investment activity in the industry has been even weaker than in the construction sector. Our forecast has been moderated from previous projections in view of the slack equipment demand in certain sectors of the industry, but still remains strong.

- Suncor Oil Sands Project

**** INCREASE IMIPM64+96.9 7.6 7.6 6.7 6.7 6.7 1982 1986
6.7 6.7 6.7 6.7 6.7 6.7 1987 1992

As in the case of construction activity discussed previously, a moderate level of machinery and equipment investment within the SUNCOR project is anticipated. These estimates are incrementally added to the exogenized projection of the equation.

- Syncrude Oil Sands Project

**** INCREASE IMIPM64+96.9	20.2	9.7	16.7	16.7	19.7	1982	1986
	19.7	19.7	19.7	19.7	19.7	1987	1992

The machinery and equipment portion of the Syncrude oil sands project investment follows the same pattern as its companion construction component. As in the case of construction investment, the partial expansion to be undertaken has been included. Investment activity levels, translated from 1975 dollars, include this investment in addition to replacement and maintenance activity throughout the period.

- Alsands Oil Sands Project

**** INCREASE IMIPM64+96.9	6.7	0.0	0.0	0.0	0.0	1982	1986
	0.0	0.0	0.0	0.0	0.0	1987	1992

The estimates for machinery and equipment investment in the Alsands project reflect the same timing as those figures connected with construction activity. Here also, the project cancellation implies no further investment expenditures beyond 1982.

- Cold Lake Oil Sands Project

**** INCREASE IMIPM64+96.9	3.4	2.5	2.5	2.5	2.5		1982	1986
	2.5	2.5	2.5	6.7	26.9	48.8		1987 1992

Minimal levels of machinery and equipment investment activity throughout most of the projection period are anticipated for the cancelled Cold Lake project. The project's revival at the turn of the decade implies some upswing in the levels of expenditure.

- Canstar Oil Sands Project

**** INCREASE IMIPM64+96.9	6.7	6.7	6.7	6.7	20.2		1982	1986
	43.8	75.7	113.6	132.9	94.2	70.7		1987 1992

With the allowance of an additional two years' delay, the Petro-Canada - Nova Canstar project is anticipated to go ahead, with the peak activity period at the end of the decade. The estimates for machinery and equipment investment activity are based on figures obtained from project personnel for the similar Alsands project.

**** INCREASE IMIPM64+96.9	8.9	9.3	9.7	10.5	11.8		1983	1987
----------------------------	-----	-----	-----	------	------	--	------	------

As in the case of construction investment, an increment has been added to crude petroleum and natural gas mining machinery and equipment investment to account for our estimate of the impact of

the extension of the 7 per cent investment tax credit to heavy construction equipment.

Transportation Investment: Construction

The equations for transportation investment have been exogenized and the pipeline portion isolated so that it may be more carefully accounted for.

**** ASSUME ITRSPC501.27 568.20 6.0 /GROW 1982 1992

The remaining portion of transportation investment, construction, which includes rail, air and ground transportation activity, has been projected to increase at an annual rate of 6.0 per cent. This is a moderate rate of growth in view of increased demands on facilities and conversion to less energy-intensive transportation forms.

- Established Pipelines

**** INCREASE ITRSPC501.27 273. 278.8 287.4 278.8 1982 1985
284.5 275.9 258.7 229.9 229.9 201.2 189.7 1986 1992

The established pipelines component includes all pipeline construction other than special projects below 60 degrees latitude or other special mega projects. There is an ongoing program of maintenance, replacement and extension investment connected with

the vast system of oil and gas pipelines that traverse the country.

The projection of established pipelines construction investment is based on figures translated into 1971 dollars for model purposes, and obtained from official sources such as EMR and other agencies.

- Special Pipeline Projects Below 60 Degrees

**** INCREASE ITRSPC501.27	270.2	189.7	149.5	138.0	1982	1985
103.5	77.6	43.1	23.0	23.0	23.0	11.5
					1986	1992

The Trans Quebec and Maritime (TQM) natural gas pipeline is the major component included in special pipeline projects below 60 degrees. Construction activity in this project is now under way, and is expected to be completed within another two years. The expenditure estimates are based on information from various agencies, and have been somewhat increased from previous estimates due to further geographic expansion and increased costs.

- Alaska Highway Gas Pipeline

**** INCREASE ITRSPC501.27	172.4	17.2	17.2	344.9	1982	1985
597.8	554.1	311.6	350.6	274.8	40.2	17.2
					1986	1992

It is assumed that the major portion of the Alaska Highway natural gas pipeline will be built, although with some delay, with peak activity levels of construction investment taking place in the 1986-87 period. The U.S. government had indicated a strong desire to bring the implementation of this project to completion and financial undertakings are still under discussion in various quarters. This assumption is perhaps considered to be optimistic, but it is envisaged that with recovery, present surplus gas conditions will moderate and alternative geographic supply locations will again become attractive.

Our estimates of construction expenditures for this pipeline are based on figures received from EMR and have been translated into 1971 dollars for model purposes. Like our other pipeline estimates, they are added by INCREASE command to the non-pipeline portion of transportation construction investment.

- Hibernia Infrastructure

**** INCREASE ITRSPC501.27	11.5	11.5	11.5	108.6	133.4	1982	1986
	157.0	28.3				1987	1988

Within the National Energy Board scenario employed in our production estimates, it has been assumed that production from Hibernia sources will come on stream in the latter half of the decade. In line with our assumptions concerning the production process for this offshore oil, it has been assumed that

expenditures on accomodating infrastructure will be made to enhance the delivery process.

Estimates of the total expenditures involved in this project construction have been gleaned from supporting documents associated with the Newfoundland Reference.¹⁹ Construction activity is anticipated to peak in the 1986-87 period.

- East Coast Gas Pipeline

**** INCREASE ITRSPC501.27 86.2 201.2 115.0 63.2 1989 1992

Construction of a natural gas pipeline linking offshore deposits with the Maritime market is assumed to take place late in the projection period. Estimates of expenditures are based on information available concerning the construction of similar projects and have been inflated to account for increased costs posed by geographic and environmental factors.

**** INCREASE ITRSPC501.27 10. 10. 15. 18. 18. 1983 1987

The extension of the 7 per cent investment tax credit to heavy construction equipment would also impact transportation construction investment expenditures. The above increment accounts for this impact.

Transportation Investment: Machinery and Equipment

**** ASSUME ITRSPM501.27 684.10 7.5 6.5 6.5 6.5 6.5 6.5
6.5 6.5 6.5 6.5 /GROW 1982 1992

The machinery and equipment portion of the non-pipeline transportation investment is assumed to increase at a rate of 6.5 per cent over the projection period. This is after a sharp reduction in expenditures in 1982. This rate is somewhat higher than that achieved over the recent past and reflects assumptions concerning factors discussed previously in connection with the construction component.

- Established Pipelines

**** INCREASE ITRSPM501.27 51.4 52.5 54.1 52.5 53.6 1982 1986
51.9 48.7 43.3 43.3 37.9 35.7 1987 1992

As in the case of construction investment, machinery and equipment investment in established pipelines activity is assumed to maintain a fairly steady flow of expenditure over the projection period. Estimates are added by the INCREASE command to the non-pipeline component of transportation machinery and equipment investment.

- Special Projects Below 60 Degrees

**** INCREASE ITRSPM501.27 50.9 35.7 28.1 26.0 19.5 1982 1986
14.6 8.1 4.3 4.3 4.3 2.2 1987 1992

Pipeline investment in special projects below 60 degrees latitude mainly comprises expenditures related to the TQM gas pipeline from Montreal to the Maritimes. Estimates of activity in the project, while increased somewhat in the near term, are assumed to decline from present peak levels to a replacement and maintenance level of investment by the end of the decade.

- Alaska Highway Gas Pipeline

**** INCREASE ITRSPM501.27 32.5 3.2 3.2 64.9 112.5 1982 1986
104.3 58.7 66.0 51.7 7.6 3.2 1987 1992

The timing of machinery and equipment investment expenditures related to the Alaska Highway natural gas pipeline is similar to that assumed for construction expenditures. The estimates of spending are based on information obtained from EMR and have been translated into 1971 dollars for model purposes. They are added by INCREASE command to other pipeline and non-pipeline transportation expenditures.

- Hibernia Infrastructure

**** INCREASE ITRSPM501.27 2.2 2.2 2.2 20.5 25.1 1982 1986
29.6 5.3 1987 1988

Machinery and equipment investment expenditures for the Hibernia offshore facilities follow the same profile as that assumed in the case of construction investment. The estimates are based on information obtained from documents associated with the Newfoundland Reference.

- East Coast Gas Pipeline

**** INCREASE ITRSPM501.27 16.2 37.9 21.6 11.9 1989 1992

The late 1980s timing of the natural gas pipeline connecting offshore deposits to the Maritime market is identical to that assumed for construction investment. As in the case of the latter assumption, estimates are based on similar pipeline expenditure patterns.

**** INCREASE ITRSPM501.27 22.4 23.6 27.2 30.1 31.3 1983 1987

The investment tax credit extension mentioned previously also affects transportation machinery and equipment investment expenditures. The above increment is our estimate of the impact of this incentive on this CANDIDE investment category.

Utilities Investment: Construction

**** ASSUME IUTILC572.9 2048.20 0.0 1.0 2.0 2.0 2.0 2.0 2.0
2.0 2.0 2.0 /GROW 1982 1992

The behavioural equation for utilities construction investment has been exogenized, and an assumption has been made concerning the profile of this investment activity over the projection period.

Recent experience in utilities investment mirrors the considerable over-capacity recorded in several areas of the industry. Some near-term reduction has been made as compared to our previous projection of this construction component. However, our conviction concerning some moderate real growth (2.0 per cent per year) in the longer run in this component remains firm. There are considerable requirements for utilities expansion, particularly in Western Canada, and particularly in relation to prospective electric power exports from thermal sources.²⁰

**** INCREASE IUTILC572.9 20. 20. 20. 21. 21. 1983 1987

The aforementioned investment tax credit extension to heavy construction equipment will impact both categories of utilities investment exogenously determined in CANDIDE. The above increment accounts for the impact on utilities construction investment.

Utilities Investment: Machinery and Equipment

**** ASSUME IUTILM572.9 1222.6 0.0 2.0 2.0 2.0 2.0 2.0 2.0
2.0 2.0 2.0 /GROW 1982 1992

As in the case of the construction component, the behavioural equation for utilities machinery and equipment investment has been exogenized. Here, the rationale behind the assumptions for the rate of growth of machinery and equipment investment in the utilities industries is similar to that discussed above in relation to construction investment. It is considered some moderate real growth will take place in the component over the longer term, and our estimates reflect this fact.

**** INCREASE IUTILM572.9 39.8 40.6 41.4 42.3 43.1 1983 1987

As in the case of utility construction investment, the tax credit extension impacts utility machinery and equipment investment, only to a greater degree. The above increment accounts for this impact.

The energy investment assumptions described in detail in this section are presented in Table 11 with the corresponding reference to the discussion in the text. All six of the investment categories discussed are behavioural equations that have been exogenized in order to more fully reflect the specific energy-related assumptions.

CONCLUSION

This completes our review of the energy assumptions in the 20th Annual Review Base Case, in particular those relating to crude petroleum and natural gas. The many energy assumptions, interwoven with the collage of relevant policy measures, are a major input into any forecast of the Canadian economy. Given the inherent volatility shown in movements in the prices of many basic energy commodities, this input can play a crucial role in the evolution of the economy through the years.

Table 1

Crude Petroleum Supply and Demand
(Million Barrels per year)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Crude Petroleum Domestic Supply¹										
Established Reserves	357.4	313.1	276.5	245.8	218.0	194.3	173.6	155.9	140.6	127.0
Reserves Additions	50.5	75.9	102.5	137.5	166.1	192.9	215.9	234.8	250.7	261.6
Pentanes Plus	40.2	40.6	38.1	36.7	33.7	31.0	26.9	23.6	22.2	21.4
Oil Sands										
- Suncor	29.8	29.8	32.1	32.1	32.1	32.1	32.1	32.1	32.1	32.1
- Syncrude	43.6	45.9	45.9	45.9	50.9	50.9	50.9	50.9	50.9	50.9
- Canstar	-	-	-	-	-	-	-	-	2.3	13.8
Frontier	-	-	-	-	-	-	-	-	-	-
- Hibernia	-	-	-	2.8	11.1	18.0	22.6	22.6	22.6	22.6
Total Productive Capacity of which New Oil ²	521.6	505.3	495.2	501.0	512.0	519.3	522.1	520.0	521.4	529.4
Adjusted Production	124.0	151.6	180.5	218.4	260.2	294.0	321.6	340.4	356.5	381.1
Crude Petroleum Demand	513.0	502.0	492.0	497.0	508.0	516.0	519.0	517.0	519.0	520.4
Total Domestic Requirement										
Export Requirement	539.1	533.7	528.4	523.2	519.0	514.9	510.8	506.7	502.6	498.6
Total Demand	66.6	34.5	24.3	16.0	10.0	10.0	10.0	10.0	10.0	10.0
Crude Petroleum Imports ³	605.7	568.2	552.7	539.2	529.0	524.9	520.8	516.7	512.6	508.6
	92.7	66.2	60.7	42.2	21.0	8.9	1.7	0.0	0.0	0.0

1 Crude Petroleum and equivalent.
2 Definition as per the Ottawa-Alberta Agreement, Sept. 1, 1981 and the 1982 Energy Update. See text pages 6 and 7.
3 Excluding SWAP imports.

Source Basic data from National Energy Board, Canadian Energy, Supply and Demand, 1980-2000, modified base case, for conventional reserves, Table 10-16, Page 147, high case for reserves additions, Table 10-17, Page 147; particular assumptions concerning timing and participation of oilfields plants by Economic Council of Canada, July 1983.

Table 2
Natural Gas Supply and Demand
(Billions of cubic feet)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Natural Gas Supply										
Established Reserves	5407.6	5577.1	5452.6	5333.6	5174.7	4830.3	4382.9	4056.7	3650.1	3247.8
Reserves Additions	66.5	150.2	284.3	446.3	618.0	791.8	962.4	1122.3	1268.2	1396.0
Total Supply Capability	5474.1	5727.3	5736.9	5779.9	5792.7	5622.1	5345.3	5179.0	4918.3	4645.8
Natural Gas Demand										
Total Domestic Requirement	2280.1	2404.8	2488.1	2565.4	2651.2	2686.6	2737.0	2825.0	2896.9	2997.8
Export Requirement ¹	1065.3	1178.5	1482.1	1646.8	1749.8	1801.2	1852.7	1904.2	1698.3	1492.4
Total Demand	3345.4	3583.3	3970.2	4212.2	4401.0	4487.8	4589.7	4729.2	4595.2	4490.2
- Domestic and Export										

¹ Some alteration to the pattern of export licences has been made to account for 1982-86 weakened market situation. See text, page 12. Figures include natural gas consumption in pipelines necessary to transmit such quantities of exports.

Source Supply - basic data from National Energy Board, Reasons for Decisions in the Matter of Phase II - The Licence Phase and Phase III - The Surplus Phase of the Gas Export Omnibus Hearing, 1982, January 1983, Table 3-14, page 32.

Demand - basic data (converted from petajoules) from National Energy Board, *Op cit*, Table 3-14, page 32.

Table 3

Petroleum and Natural Gas Supply and Demand Inputs in the Base Case
(Millions of 1971 dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
	Base Value (level)											
Imports												
Crude Petroleum Imports ¹	270.372	257.9	199.8	187.8	147.2	100.8	74.3	58.5	54.8	54.8	54.8	13
Imports of Fuel Products ¹ - % change	100.147	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	14
Exports												
Crude Petroleum Exports ¹	222.63	264.8	172.9	143.5	119.3	101.9	101.9	101.9	101.9	101.9	101.9	15
Exports of Fuel Products ¹ - % change	239.146	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	16
Exports of Natural Gas ¹	216.378	295.7	327.1	411.4	457.1	485.7	499.9	506.8	528.6	471.4	414.3	16
Domestic Consumption												
Fuel Oil Products ² - % change	-434.300	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	- 1.3	17
Natural Gas ² - % change	465.700	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	17

- 1 Exogenous variable.
2 Equation has been exogenized.

Table 4
Pattern of Short-term International Crude Petroleum
Pricing (Base Case)

Country of Origin	Average Price (\$US) 1981	Per Cent of Imports 1981	Average Price (\$US) 1982	Per Cent of Imports 1982 ¹	Assumed Price (\$US) 1983
United Kingdom	36.66	5.7	31.85	8.4	29.40
Iran	--	--	32.95	2.9	28.00
Kuwait	34.12	2.5	--	--	--
Saudi Arabia	32.30	35.6	33.40	18.2	28.50
Algeria	39.29	5.5	33.85	6.3	30.50
Venezuela	33.72	33.3	32.70	41.3	29.84
Mexico	33.61	11.0	29.84	18.8	25.42
Other Countries	33.95	7.4	37.30	4.1	28.00
Weighted Total Price (\$US) ²	34.040		32.65		28.86
Weighted Total Price (\$Can) ²	40.014		40.29		35.62

1 Excludes "Swap" imports from the United States.

2 Includes "Swap" imports from the United States since the sales of these imports are included in the Trade of Canada figures.

Source Data from Trade of Canada, various issues. Estimates for 1983 by Economic Council of Canada, July 1983.

Table 5

Crude Petroleum Pricing Assumptions
(Base Case)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Crude Petroleum Prices (\$ per barrel)											
International Price (at source)	40.290	35.616	37.361	39.491	41.742	44.330	46.679	48.873	50.975	53.473	56.039
Per Cent Change - Real Inflation ¹	-8.6	-16.2	0.0	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5
International Price (at Montreal)	5.9	4.6	4.9	5.7	5.2	5.7	4.8	4.2	3.8	4.4	4.3
Per Cent Change	41.99	37.36	39.16	41.35	43.65	46.30	48.71	50.96	53.12	55.69	58.32
Blended Price (to Domestic Market) ²	-0.6	-11.0	4.8	5.6	5.6	6.1	5.2	4.6	4.2	4.8	4.7
Per Cent Change	33.65	35.55	36.85	38.55	40.95	43.74	46.41	48.97	51.42	54.18	56.94
Old "Old" Oil Wellhead Price ³	22.6	5.6	3.7	4.6	6.2	6.8	6.1	5.5	5.0	5.4	5.1
Per Cent of World Price at Montreal ⁴	24.63	29.75	29.75	30.07	31.76	33.70	35.46	37.10	38.67	40.54	42.46
Old "New" Oil Wellhead Price ⁵	60.2	82.1	78.3	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
New Oil Reference Price (MORP)	27.67	32.99	37.97	40.10	42.34	44.93	47.27	49.46	51.56	54.05	56.61
	40.90	36.22	37.97	40.10	42.34	44.93	47.27	49.46	51.56	54.05	56.61

- 1 Inflation as measured by the rate of change in the US GNP price deflator in the Wharton June 1983 Post-Meeting Forecast.
- 2 Includes Canadian Ownership Charge.
- 3 Estimate for 1983 includes the present wellhead price of \$29.75 to be maintained until the 75 per cent parity is resumed, after which time the wellhead price will increase as the ceiling allows. This is the substance of the June 1983 Amendment to the Ottawa/Alberta Agreement.
- 4 Calculation includes wellhead price plus transportation.
- 5 1983 calculation includes the increment to the revised SGOEP level as of July 1, 1983.

Source: Economic Council of Canada, July 1983.

Table 6
Natural Gas Pricing Assumptions
(Base Case)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Natural Gas Prices (\$ Can/Mcf)											
Field Export Price	5.80	4.92	4.90	5.13	5.42	5.74	6.01	6.26	6.48	6.76	7.03
Parity with Oil International Price	.860	.840	.820	.820	.820	.820	.820	.820	.820	.820	.820
Domestic Toronto City Gate Price ¹	4.03	4.26	4.12	4.78	5.46	5.72	5.97	6.22	6.47	6.74	7.05
Parity with Domestic Oil Price ²	.695	.695	.648	.719	.773	.758	.746	.737	.730	.722	.718
Average Wellhead Price	1.91	2.39	2.64	3.10	3.56	3.56	3.56	3.56	3.56	3.56	3.56

¹ Includes Canadian Ownership Charge.

² 65 per cent btu equivalency has not been enforced as per specification in the Amendment to the Ottawa/Alberta Agreement.

Source: Economic Council of Canada, July 1983.

Table 7

Crude Petroleum and Natural Gas Pricing Inputs in the Base Case
Percentage Change (1971=1,000)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
	Base Value (level)											
Foreign Trade Deflator Exports												
Crude Petroleum ¹	9.9310	-11.6	2.3	4.6	5.3	5.7	4.7	4.1	3.6	4.2	4.0	21
Natural Gas ¹	17.8060	-13.9	-0.1	4.6	5.3	5.7	4.7	4.1	3.6	4.2	4.0	21
Fuel Products Exports ¹	8.5260	-2.5	2.5	4.0	4.5	4.0	4.0	4.0	4.0	4.0	4.0	22
Imports												
Crude Petroleum ¹	14.90398	-11.6	4.9	5.7	5.7	6.2	5.3	4.7	4.3	4.9	4.6	23
Fuel Product Imports ¹	7.03914	-2.5	2.5	4.0	4.5	4.0	4.0	4.0	4.0	4.0	4.0	23
Domestic Deflators Consumer Deflators Other Fuels (mainly heating oil) ²	6.29022	5.4	3.5	4.4	6.0	6.6	5.9	5.4	4.9	5.2	5.0	26
Gasoline, Oil and Grease ²	3.86075	9.6	4.5	3.6	4.6	5.4	5.3	4.9	4.5	4.5	4.5	27
Natural Gas ²	4.43599	11.8	3.5	6.1	10.4	10.0	6.3	4.2	4.0	4.0	4.2	31
Value Added Deflator Crude Petroleum & Natural Gas Mining ²	9.90771	24.3	11.5	13.5	11.7	2.5	2.8	2.7	2.4	2.3	2.4	27

1 Exogenous variable.

2 Equation has been exogenized.

Table 8
Taxation and Transfer Assumptions and Adjustments in the Base Case
(Millions of dollars)

[illegible]

Table 8 (concl'd)
Taxation and Transfer Assumptions and Adjustments in the Base Case
(Millions of dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
Direct Taxes²												
Corporation Direct Taxes												
Basic Additive Adjustment	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	-2091.7	42
Petroleum & Gas Revenue Tax												
(INCREASE)	1613.0	2792.0	2984.0	3309.0	3668.0	3875.0	4005.0	4084.0	4139.0	4047.0	3952.0	42
Small Producers' PGRT Exemption												
(DECREASE)	231.2	342.3	259.0	196.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5	44
Enhanced Oil PGRT Modification												
(DECREASE)	0.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	44
Incremental Oil Revenue Tax												
(INCREASE)	205.0	565.0	682.0	353.0	125.0	22.0	0.0	0.0	0.0	0.0	0.0	45
Aviation Turbine Fuels Tax (INCREASE)	55.3	19.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	47
Net Corporate Taxable Income¹												
Basic Additive Adjustment	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	2071.04	47
Budget Factors	3280.	3305.	2045.	1722.	1961.	2239.	2530.	2859.	3231.	3451.	3600.	47
Gross Incremental Revenue												
Deduction	1828.2	1694.7	2017.0	958.7	305.9	53.0	0.0	0.0	0.0	0.0	0.0	48
Federal Transfers to Provinces, Other¹												
Basic Assumption	1498.8	1500.	1500.	1500.	1500.	1500.	1500.	1500.	1500.	1500.	1500.	49
Transfer of Crude Oil Export Tax												
(INCREASE)	502.2	198.9	116.9	98.7	67.8	44.0	45.2	46.1	46.6	47.3	47.7	49
Provincial Tax Rate on Diesel Fuel												
& Gasoline ¹ - % change	.35207	7.6	2.5	1.6	2.6	3.4	3.3	2.9	2.5	2.5	2.5	50

1 Exogenous Variable.
2 Endogenous Variable.

Table 9 (concl'd)
Subsidy and Capital Assistance Assumptions in the Base Case
(Millions of dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
Capital Assistance												
Federal Capital Assistance ¹												
Basic Assumption - % change	864.0	6.5	5.5	6.1	6.9	6.4	6.4	6.4	6.4	6.4	6.4	57
Petroleum Incentive Programs (INCREASE)	935.2	1056.5	1369.2	1780.0	1722.8	1681.7	1595.4	1523.9	1446.5	1361.4	1310.0	57
Lateralis Fund (INCREASE)	0.0	70.0	140.0	140.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58
Unidentified Programs (INCREASE)	491.8	1540.9	1913.5	2191.6	2295.2	2405.7	2405.7	2405.7	2405.7	2405.7	2405.7	59
Additional re Special Recovery Program (INCREASE)	0.0	122.97	181.34	112.69	22.0	0.0	0.0	0.0	0.0	0.0	0.0	60
Capital Assistance to Persons ¹												
Basic Assumption - % change	435.800	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	60
Canada Oil Substitution Program (INCREASE)	203.2	263.0	287.0	312.0	312.0	312.0	312.0	312.0	312.0	312.0	312.0	61
Canadian Home Insulation Program (INCREASE)	225.0	247.5	272.3	299.5	329.4	360.0	360.0	360.0	360.0	360.0	360.0	61
Canada Home Renovation Plan (INCREASE)	0.0	90.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62
Provincial Capital Assistance ¹												
Basic Assumption - % change	220.7	6.5	5.5	6.1	6.9	6.4	6.4	6.4	6.4	6.4	6.4	62
Alberta Canadianization Grants (INCREASE)	0.0	180.0	300.0	450.0	550.0	500.0	500.0	500.0	500.0	500.0	500.0	63
Petroleum Incentive Programs (INCREASE)	191.3	704.0	872.0	1093.0	1062.0	1029.0	994.0	955.0	913.0	868.0	840.0	63

1 Exogenous Variable
2 Endogenous Variable

Table 10
Royalty Assumptions in the Base Case
(Millions of dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
	Base Value (Level)											
Federal Royalties ¹	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	65
Provincial Royalties ¹												
Basic Assumption	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	66
Old Oil Royalties	3886.8	4200.0	3578.0	3059.0	2728.0	2426.0	2138.0	1847.0	1566.0	1312.0	1076.0	66
New Oil Royalties	376.0	818.0	1041.0	1258.0	1640.0	1983.0	2321.0	2608.0	2863.0	3134.0	3361.0	67
Oil Sands Royalties	281.0	394.0	407.0	425.0	449.0	477.0	502.0	525.0	547.0	592.0	716.0	68
Hibernia Royalties	0.0	0.0	0.0	0.0	11.1	68.7	103.3	129.7	135.2	141.7	148.5	69
Gas Export Royalties	1551.0	1600.0	1764.0	2122.0	2729.0	3073.0	3318.0	3554.0	3787.0	3523.0	3223.0	70
Old Gas Royalties	826.0	1084.0	1242.0	1502.0	1741.0	1706.0	1615.0	1498.0	1397.0	1319.0	1251.0	71
New Gas Royalties	5.4	22.4	57.2	141.0	270.0	396.0	544.0	739.0	951.0	1118.0	1299.0	72
Crown Corporation Profits Adjustment	735.2	797.2	784.1	883.7	960.5	1023.5	1061.7	1097.4	1133.1	1041.0	941.4	73
Profits of Government Business Enterprises ²												
Basic Additive Adjustment	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	-76.358	73
Crown Corporation Profits Adjustment	735.2	797.2	784.1	883.7	960.5	1023.5	1061.7	1097.4	1133.1	1041.0	941.4	74
Federal Income Resettlements ²												
Basic Additive Adjustment	782.811	782.811	782.811	782.811	782.811	782.811	782.811	782.811	782.811	782.811	782.811	74
Crown Corporation Profits Offset (INCREASE)	-375.0	-406.6	-399.9	-450.7	-489.9	-522.0	-541.5	-559.7	-577.9	-530.9	-480.1	74

Table 10 (concl'd)
Royalty Assumptions in the Base Case
(millions of dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
Municipal Income Remittances ²												
Basic Additive Adjustment	-40.407	-11.799	-11.799	-11.799	-11.799	-11.799	-11.799	-11.799	-11.799	-11.799	-11.799	75
Crown Corporation Profits Offset (INCREASE)	-31.8	-33.4	-39.0	-34.1	-36.7	-45.1	-46.1	-46.4	-46.5	-47.7	-41.2	75

1 Exogenous Variable
2 Endogenous Variable

Table 11
Energy Investment Assumptions in the Base Case
(Millions of 1971 dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
	Base Value (Level)											
Crude Petroleum and Natural Gas Mining Construction ¹	1549.40	6.5	6.0	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	76
Basic Assumption - % change												
Suncor Oil Sands Project (INCREASE)	22.8	22.8	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	77
Syncrude Oil Sands Project (INCREASE)	60.7	25.2	45.2	45.2	50.2	50.2	50.2	50.2	50.2	50.2	50.2	78
Alsands Oil Sands Project (INCREASE)	20.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	79
Cold Lake Oil Sands Project (INCREASE)	10.1	7.6	7.6	7.6	7.6	7.6	7.6	7.6	20.2	81.0	146.8	79
Canstar Oil Sands Project (INCREASE)	20.2	20.2	20.2	20.2	60.7	131.6	227.8	341.7	399.9	283.5	212.6	80
7% Investment Tax Credit Impact (INCREASE)	0.0	21.0	22.0	23.3	25.0	27.0	0.0	0.0	0.0	0.0	0.0	80
Machinery and Equipment ¹												
Basic Assumption - % change	255.8	6.0	5.5	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	81
Suncor Oil Sands Project (INCREASE)	7.6	7.6	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	81
Syncrude Oil Sands Project (INCREASE)	20.2	9.7	16.7	16.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	82
Alsands Oil Sands Project (INCREASE)	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	82
Cold Lake Oil Sands Project (INCREASE)	3.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	6.7	26.9	48.8	83
Canstar Oil Sands Project (INCREASE)	6.7	6.7	6.7	6.7	20.2	43.8	75.7	113.6	132.9	94.2	70.7	83
7% Investment Tax Credit Impact (INCREASE)	0.0	8.9	9.3	9.7	10.5	11.8	0.0	0.0	0.0	0.0	0.0	83

Table 11 (cont'd.)

Energy Investment Assumptions in the Base Case
(Millions of 1971 dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
Transportation Construction¹												
Basic Assumption - % change	568.20	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	84
Established Pipeline (INCREASE)	273.0	278.8	287.4	278.8	284.5	275.9	258.7	229.9	229.9	201.2	189.7	84
Special Pipeline Projects below 60 degrees (INCREASE)	270.2	189.7	149.5	138.0	103.5	77.6	43.1	23.0	23.0	23.0	11.5	85
Alaska Highway Gas Pipeline (INCREASE)	172.4	17.2	17.2	344.9	597.8	554.1	311.6	350.6	274.8	40.2	17.2	85
Hibernia Infrastructure (INCREASE)	11.5	11.5	11.5	108.6	133.4	157.0	28.3	0.0	0.0	0.0	0.0	86
East Coast Gas Pipeline (INCREASE)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.2	201.2	115.0	63.2	87
7% Investment Tax Credit Impact (INCREASE)	0.0	10.0	10.0	15.0	18.0	18.0	0.0	0.0	0.0	0.0	0.0	87
Machinery and Equipment¹												
Basic Assumption - % change	684.10	7.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	88
Established Pipelines (INCREASE)	51.4	52.5	54.1	52.5	53.6	51.9	48.7	43.3	43.3	37.9	35.7	88
Special Projects Below 60 Degrees (INCREASE)	50.9	35.7	28.1	26.0	19.5	14.6	8.1	4.3	4.3	4.3	2.2	89
Alaska Highway Gas Pipeline (INCREASE)	32.5	3.2	3.2	64.9	112.5	104.3	58.7	66.0	51.7	7.6	3.2	89
Hibernia Infrastructure (INCREASE)	2.2	2.2	2.2	20.5	25.1	29.6	5.3	0.0	0.0	0.0	0.0	90
East Coast Gas Pipeline (INCREASE)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	37.9	21.6	11.9	90
7% Investment Tax Credit Impact (INCREASE)	0.0	22.4	23.6	27.2	30.1	31.3	0.0	0.0	0.0	0.0	0.0	90

Table 11 (concl'd)
Energy Investment Assumptions in the Base Case
(Millions of 1971 dollars)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	Page Reference in Text
Utilities												
Construction ¹												
Basic Assumption - % change	2048.20	0.0	1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	91
7% Investment Tax Credit Impact	(INCREASE) 0.0	20.0	20.0	20.0	21.0	21.0	0.0	0.0	0.0	0.0	0.0	91
Machinery and Equipment ¹												
Basic Assumption - % change	1222.6	0.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	92
7% Investment Tax Credit Impact	(INCREASE) 0.0	39.8	40.6	41.4	42.3	43.1	0.0	0.0	0.0	0.0	0.0	92

¹ Equation has been exogenized.

Footnotes

- 1 National Energy Board, Canadian Energy, Supply and Demand, 1980-2000, June 1981.
- 2 Memorandum of Agreement between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation, September, 1981.
- 3 The National Energy Program, Update 1982, Energy, Mines and Resources Canada, 1982.
- 4 Agreement to Amend the Memorandum of Agreement of September 1, 1981 between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation, June 30, 1983.
- 5 For further elaboration see pages 42 to 45 of the National Energy Program, Energy, Mines and Resources Canada, 1980.
- 6 Update 1982, op cit, pages 81-84.
- 7 National Energy Program, op cit, pages 99-102.
- 8 National Energy Board, Reasons for Decisions in the Matter of Phase II - The Licence Phase and Phase III - The Surplus Phase of the Gas Export Omnibus Hearing, 1982, January 1983.
- 9 Speech by the Honourable Jean Chretien, Minister of Energy, Mines and Resources, to Calgary Chamber of Commerce, Calgary, Alberta, April 11, 1983; and Energy, Mines and Resources Canada Communique, "Incentive Pricing for Natural Gas Exports Announced", July 6, 1983.
- 10 For a full explanation of this terminology, please refer to the Preface.
- 11 National Energy Board, Canadian Energy, Supply and Demand, op cit, Table 7-23, page 83.
- 12 Hansard, House of Commons Debates, Vol. 124, Number 486, 1st Session, 32nd Parliament, Wednesday, March 30, 1983, page 24298.
- 13 Memorandum of Agreement, op cit, pages 8 and 9.
- 14 The definition of old oil is that described in the section on oil pricing.
- 15 For further description of the sources of this adjustment see B.L. Eyford, "Background Paper to 19th Annual Review on Government Revenues and Expenditures", mimeo, July 1982.
- 16 For further details, see the table on page 90 of the National Energy Program, op cit.

17 It is considered that the nature of the incentive grants is more appropriate to capital assistance, i.e., grants towards programs of a more capital allocation such as plant expansion and construction, etc.

18 The Alberta Oil and Gas Activity Program, Announcement by Premier Lougheed and Energy Minister Merv Leitch, Calgary, Alberta, April 13, 1982.

19 The work of J. Wilby has been particularly helpful in this respect. Jonathan Wilby, Revenue Implications of Offshore Oil Under Different Taxation and Profit-Sharing Regimes: The Case of Hibernia, Economic Council of Canada, Discussion Paper No. 197, March 1981.

20 See, for example, "Forecasts for Demand of Electricity: 1980-2000" in Nuclear Policy Review, Background Papers, Energy, Mines and Resources Canada, 1980.

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QUALITY

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